

8.0 AC MOTORS

Learning Objectives

After studying this chapter, you should be able to:

1. Describe the factors that affect the synchronous speed of a motor.
2. Define "slip" and explain the factors that cause slip to change.
3. Explain the operation of a three-phase induction motor including its reaction to an increase in load.
4. Describe the operation of the following types of single-phase AC motors:
 - a. Shaded - pole
 - b. Induction - start
 - c. Capacitor - start
5. Describe the operation of a synchronous motor.
6. Explain why starting current is greater than running current in an AC induction motor.
7. Describe the relationship between rotor current, slip, and torque in an AC induction motor.
8. Describe why some motors have starting limits or restart limits.
9. Describe the operation and purpose of motor controllers using full-voltage, primary-resistor, or autotransformer starters.
10. State the relative advantage of synchronous and induction motors.

8.1 Introduction

Most of today's power generating systems

produce alternating current. Therefore, a majority of motors used in commercial industry are designed to operate on alternating current (AC). However, besides the wide availability of AC power, AC motors offer other advantages. In general, AC motors are less expensive. Because they do not employ commutators, AC motors eliminate the problem of dangerous sparking and frequent brush replacement associated with DC systems. AC motors are manufactured in many different sizes, shapes, and ratings for use on a great many different jobs. They are designed for use with either three-phase or single-phase power systems. This chapter will deal with the operating principles of three of the more common types of AC motors — the induction motor, the single-phase motor, and the synchronous motor.

8.2 AC Motor Theory

8.2.1 Development of a Rotating Field

Both induction and synchronous motors utilize a rotating magnetic field. The field is produced in the motor stator windings. These windings are symmetrically placed on the stator and may be either wye or delta connected. Figure 8-1 illustrates a rotating field produced by currents in the stator's stationary coils, or windings, supplied by a three-phase power source. Field rotation can be observed in the figure by "stopping" it at six selected positions, or instants. These instants are marked off at 60° intervals on the sine waves that represent currents in the three phases (A, B, and C).

At t-1, the current in phase B is maximum positive and current in phases A and C is at half negative value. The resulting field at t-1 is established downward and to the left (7 o'clock). The major portion of this field is produced by the B phase (maximum current) and is aided by the adjacent phases A and C (half strength). The direction of the magnetic field resulting from current flow through a coil of wire may be determined by wrapping the fingers of your right hand in the direction that current flows around the coil.

Your thumb will then point in the direction of the resulting magnetic field.

Because the fields effectively combine to form one field of a given direction and strength, this is a two-pole field (one north and one south pole). This two-pole field extends across the space that would normally contain the rotor.

At t-2, current in phase B is reduced to half positive value. Current in phase C has reversed direction and is positive, and current in phase A has increased to a maximum negative value. The resulting field at t-2 is now established downward and to the right (5 o'clock). The major portion of the field is produced by phase A (full strength) and the weaker portions by phases B and C (half strength). Thus the magnetic field has rotated counterclockwise. This process continues at a speed determined by the applied frequency (60 Hz for grid loads).

The direction of rotation of the magnetic revolving field of a three-phase motor may be reversed by interchanging any two line leads to the three motor terminals.

8.2.2 Motor Synchronous Speed

In Figure 8-1, current sine waves traversed 300° for the six positions shown. Accordingly, the field rotated 300°. If the frequency of current were 60 Hz, the field would rotate at 60 revolutions per second or 3600 revolutions per minute ($60 \times 60 = 3600$). However, if the number of stator coils were doubled, producing a four-pole field, the field would rotate only half as fast. Thus, it can be seen that speed of the rotating field varies directly with the frequency of applied voltage and inversely with the number of stator poles; therefore:

$$N = \frac{120f}{P}$$

where

N = the number of revolutions that the field makes per minute,

f = the frequency of the applied voltage in cycles per second (Hz), and

P = the number of poles.

The speed at which an AC motor field rotates is referred to as its synchronous speed, because it is synchronized to the power supply frequency. A two-pole motor connected to a 60-Hz source has a synchronous speed (magnetic rotating field speed) of 3600 rpm; a four-pole motor, 1800 rpm; and a six-pole motor, 1200 rpm.

The speed of the rotating field is always independent of motor load changes. Because the number of poles in a motor is fixed (some special application motors have variable poles), the only variable that can affect synchronous speed of an operating motor is the applied frequency.

8.2.3 AC Motor Losses and Efficiency

The efficiency of any motor is equal to the ratio of the output power to input power. The difference between output and input power is attributed to motor losses.

Losses in an AC motor can be attributed to I^2R losses as a result of rotor and stator currents, rotor windage, and bearing friction losses (which together are termed mechanical losses), and finally magnetic field or core losses.

Because the current flow in an AC motor is constantly changing in magnitude and direction and there are many coils wrapped around the stator, AC motors develop a large amount of inductive reactance (X_L), which decreases motor current but is not considered a motor loss.

Running at full load conditions, the efficiency of most AC motors can be expected to be 92% to 96%.

8.3 Three-Phase Induction Motors

Three-phase induction motors are the most common type of three-phase motor. They have the advantage of simple, rugged construction, which makes them relatively inexpensive. Induction motors also have high starting torque and desirable torque/speed characteristics under normal load. They are used in applications such as fans, blowers, pumps, and compressors where high starting torque and limited speed control is required.

8.3.1 Induction Motor Construction

The stator of an induction motor is very similar to the stator of a three-phase AC generator and is also similar to the stator of a synchronous motor. Line voltage is applied to the three phases of the stator to produce a rotating magnetic field as described in section 8.2.1.

The two types of induction motors are differentiated by the rotor designs. A squirrel cage induction motor uses a caged rotor as shown in Figure 8-2A. Copper bars are connected at the ends by a copper ring called a shorting ring. The squirrel cage induction motor is inexpensive, simple, and very rugged. A typical squirrel cage motor is illustrated in Figure 8-2B.

The second type of induction motor is the wound rotor induction motor. This rotor design has the advantage of improved speed control because resistors can be placed in series with the rotor windings. The rotor is wound with three-phases each with leads connected to slip rings. Brushes pick up the rotor current and carry it to a bank of external resistors. Rotor circuit resistance is then adjusted for the desired speed. A schematic view of this arrangement is shown in Figure 8-3A, and a cutaway view of an actual motor is shown in Figure 8-3B. Wound rotor induction motors are more complex, expensive, and less rugged than

squirrel cage rotor motors and require much more frequent maintenance.

8.3.2 Induction Motor Operation

As its name implies, induction motor operation is based on the principle of electromagnetic induction. Three-phase AC line voltage is applied to the stator of the induction motor, resulting in stator current and a rotating magnetic field. Recall that the stator field rotates at synchronous speed as determined by the number of stator poles and the frequency of the applied voltage.

Relative motion between the rotating magnetic field and the bars or conductors on the rotor cause a voltage to be induced in the conductors of the rotor. Because the conductors of the rotor are shorted at their ends, there is a complete path for rotor current to flow. This rotor current flowing around the conductors in the rotor creates a rotor magnetic field. The rotor magnetic field and stator magnetic field interact to produce torque to turn the rotor.

Relative motion must exist between the stator magnetic field (turning at synchronous speed) and the rotor in order for voltage to be induced, rotor current to flow, a rotor magnetic field to be produced, and torque to be generated. The relative motion is a result of the difference between synchronous speed and rotor (operating) speed and is called slip speed or simply slip (s). Slip is most frequently expressed as a fraction or percent of synchronous speed; that is:

$$S = \frac{N_s - N_r}{N_s}$$

where

S = slip

N_s = speed of stator field (synchronous speed) in rpm, and

N_r = speed of the rotor in rpm.

8.3.3 Induction Motor Response to an Increase in Load

As the load on an induction is increased, an immediate mismatch occurs between the torque of the load and the torque provided by the motor. As a result, the rotor slows down. This causes slip to increase (more relative motion between the stator field and the rotor). This in turn results in more voltage induced in the rotor, more rotor current, and a stronger rotor field. Thus, the motor torque increases until the torque of the motor matches the torque of the load in steady state at a new, slower speed.

The speed of an induction motor changes with load over its operating range. However, the change is relatively small and does not prevent the motor from having many applications. Typical values of slip for an induction motor range from 0.03 to 0.05 at full load for a low slip motor and 0.07 to 0.11 for a medium slip motor.

8.4 Single-Phase AC Motors

For economical purposes, the electrical distribution systems that provide power to the many small AC motors used in nuclear plants typically provide only single-phase AC power at low voltages and current flows. The induction motors described in section 8.3 will not work with single-phase AC because a rotating field cannot be generated in the stator by single-phase power unless the stator windings and/or the stator power supply circuit are appropriately modified.

Because a rotating field is not generated in a single-phase motor, an unmodified motor would produce no starting torque on a stationary rotor. After the rotor starts rotating, however, a continuous turning torque is generated by the interaction of the stator and rotor magnetic fields. Therefore, single-phase AC motors must be provided with an auxiliary means for initiating the rotor rotation. Single-phase AC motors are frequently classified in the following groups, based on the method used for starting the rotor rotation:

1. Shaded - pole
2. Induction - start
3. Capacitor - start

8.4.1 Shaded Pole Single-Phase Motors

Some fractional horsepower single-phase motors are started by using shading coils to create shaded poles as shown in Figure 8-4. The stator winding of these motors is distributed around the frame on projecting pole pieces. In addition to the main stator winding, a short-circuited heavy-wire coil, or shading coil, is placed around a portion of each pole piece. This shading coil makes the flux in that portion of the pole piece lag behind the flux produced by the main portion of the pole. The out-of-phase flux fields interact to produce a distorted overall field that rotates, developing sufficient torque to start small motors under very light load conditions. These motors produce fractional horsepower and are frequently used for equipment such as hair dryers, clocks, and small fans employed to cool electronic equipment.

8.4.2 Induction-Start Single-Phase Motors

The induction-start single-phase motor is provided with an auxiliary stator winding in addition to the main stator winding. This winding is located in the stator slots so that it is displaced 90 electrical degrees from the main stator winding as shown in Figure 8-5. If two currents sufficiently out of phase with each other are passed through the main and auxiliary windings, interacting field conditions similar to those existing in a three-phase induction motor will be produced. The two necessary currents, which are from 30 to 45 degrees out of phase with each other, are obtained from the single-phase AC power input by constructing parallel winding circuits, with one of the circuits having a relatively high inductance and the other having a relatively high resistance. The main or running winding always has the high inductance. The auxiliary winding is wound with a finer wire, giving it higher resistance than the main winding. The running or main winding remains in the circuit whenever the motor is running, while the auxiliary

or stator winding remains in the circuit only until the motor has reached 50 to 80 percent of synchronous speed. When the rotor reaches this speed, an automatic centrifugal switch operates to open the starting circuit. This type of single-phase induction motor starts as a "two-phase" motor until the starting winding is isolated, when it continues to operate, by virtue of the running winding only, as a single-phase motor. Induction-start motors are constant speed machines, and cannot be adapted for speed control. They are made in sizes up to a third horsepower.

8.4.3 Capacitor-Start Single-Phase Motors

Capacitor-start motors are single-phase induction motors that have two stator windings displaced 90 electrical degrees from each other similar to the induction-start motor. Again, the starting torque is developed by a two-phase action. In the capacitor-start motor, the necessary phase displacement between the currents of the two stator windings is produced by placing a capacitor in series with the auxiliary winding as shown in Figure 8-6. By using a capacitor, the phase displacement can be made to approach 90 degrees, which results in a better starting torque with lower starting current than can be obtained with the induction-start motor. Capacitor-start motors have the advantages of quiet operation, high power factor, and a reduction in radio interference. These motors are made in various sizes up to 10 horsepower.

8.5 Synchronous Motors

8.5.1 Synchronous Motor Operation

The stator or armature windings of induction and synchronous motors are essentially the same. However, their rotors differ in several ways. The rotor of a typical synchronous motor is essentially the same as that of a generator. It requires a separate source of DC voltage to the rotor (rotor current is not induced) to create the rotor field. Because no relative motion between rotor and rotating stator field is required, the opposite poles

of the rotor and stator will lock together. The rotor will then turn at the speed of the revolving field; therefore, it is "synchronized." The simplest synchronous motor is a permanent bar magnet that rotates at the speed of the stator's rotating field. In actuality this would be called a reluctance motor.

A synchronous motor also requires special starting components. Because the field of the stator is revolving very rapidly and the rotor field is established by an external source, the rotor will attempt to instantly lock in with the stator field. Because of inertia, the rotor cannot instantly come up to synchronous speed. Therefore, the rotor will not pull into synchronization and will vibrate back and forth. To aid in the starting process, a small squirrel cage winding (also called the amortisseur winding) is included in the rotor. When the motor is first started, the DC field is not energized. Slip induces current in the rotor and the rotor starts to speed up. If the motor is allowed to run at less than synchronous speed for an extended period, the small squirrel cage winding will overheat. When the motor approaches synchronous speed, the DC rotor field is energized. This causes the rotor to pull into synchronization. Because no slip exists, no current is induced in the small squirrel cage winding, protecting it from overheating.

8.5.2 Synchronous Motor Speed

Synchronous motors run at a fixed (synchronous) speed determined by line frequency and the number of poles in the machine. Therefore, *speed of a synchronous motor is independent of load* and follows the previously described equation for motor synchronous speed as

$$N = \frac{120f}{P}$$

where

N = number of rpm/min of the field *and* the rotor,

f = frequency of applied voltage in cycles per second, and

P = number of field poles of rotor.

However, if load on the rotor shaft becomes too great for the magnetic lock between the rotor and stator, the rotor will pull out of synchronization and stall. This can be prevented by increasing DC rotor current to increase the magnetic lock before increasing the load.

8.5.3 Overexcited Synchronous Motors

For a fixed mechanical power developed (load), it is possible to adjust the reactive component of the current drawn by the synchronous motor from the line by varying the DC field current (excitation). This provides the ability to control the electrical angle between the voltage applied to the terminals of the motor and the motor stator current and thus control the reactive power associated with the synchronous motor.

This is possible because the magnetic field of the rotor induces a second voltage in the stator windings in addition to the applied voltage from the line. The net current flowing in the stator then is the result of the combination of these two voltages. Remember that the stator current is the source of the stator magnetic field which pulls the rotor magnetic field in synch.

As excitation is increased, the strength of the rotor magnetic field increases and the torque provided by the motor tends to increase (the force between the rotor field and stator field tends to increase). This does not occur, however, because the load is fixed and the motor cannot speed up above synchronous speed. The voltage induced in the stator by the rotor field in this situation combines with the applied (line) voltage to produce a leading reactive current that acts to reduce the total magnetic flux of the machine until the torque of the motor matches the torque of the load.

When the excitation of a synchronous motor is increased so that it operates with a leading power factor, it is said to be overexcited.

The ability of the synchronous motor to draw leading current when overexcited can be used to

improve the power factor at the input lines to an industrial establishment that makes heavy use of induction motors and other equipment drawing power at a lagging power factor. Many electric power companies charge increased power rates when power is bought at a very lagging power factor. Over the years such increased power rates can result in an appreciable expenditure of money. In such instances the installation of a synchronous motor operated overexcited can more than pay for itself by improving the overall input power factor to the point where the increased rates no longer apply.

8.5.4 Synchronous Motor Applications

Synchronous motors below 50 hp are rarely used in the medium-speed (500 rpm) range because of their much higher initial cost compared to induction motors. In addition, these motors require a DC excitation source, and the starting and control devices are usually more expensive—especially where automatic operation is required. However, synchronous motors do offer some very definite advantages. These include constant-speed operation, power-factor control, and high operating efficiency. Furthermore, there is a horsepower and speed range where the disadvantage of higher initial cost vanishes, even to the point of putting the synchronous motor to advantage. This is demonstrated in Figure 8-7. When low speeds and high horsepower are involved, the induction motor is no longer cheaper because it must use large amounts of iron in order not to exceed flux density limits. However, high flux densities are permissible in the synchronous machine because of the separate excitation.

Some of the more important characteristics of the synchronous motor along with some typical applications are shown in Table 8-1.

8.6 Motor Starting Current

Recall from the Chapter 6 discussion of transformers that counter emf refers to the voltage induced in a winding that opposes or is counter to

the change in current that produces it. In the case of an AC motor, the counter emf results from relative motion between the net (combined stator and rotor) magnetic field and the conductors in the stator. AC motor counter emf opposes the current applied to the stator.

When an AC motor is first started, there is NO counter emf to oppose stator current flow. Therefore, the starting current of an AC motor started at full voltage is 7 to 10 times the normal running current. The equation for current flowing through an AC motor stator is shown as Equation 8-1:

$$I_s = \frac{E_s - E_c}{Z_s} \quad (8-1)$$

where

I_s = the current flowing through the stator,
 E_s = the applied voltage across the stator,
 E_c = the counter emf, and
 Z_s = the total impedance of the stator.

A typical AC motor starting current curve is shown in Figure 8-8. As rotor speed increases, counter emf increases, lowering stator current between points A and B. The starting current continues to decrease until the rotor reaches its normal running speed for the shaft load. The current drawn at normal speed is called the running current (point C).

If the motor start in Figure 8-8 were observed on an ammeter, the current would initially spike to 7 to 10 times normal running current. As motor speed increases, the indicated current would drop to the normal running current.

8.6.1 No-Load Starting

When an AC motor is unloaded by reducing the shaft load, the required torque is minimum (just enough to overcome friction and rotor windage losses). Therefore, the required stator current is much less than if the motor were running loaded.

Some AC motors are started unloaded to limit starting current. The unloaded rotor increases to rated speed with no-load running amperage in a short time period. Then the motor load can be slowly increased to normal. No-load starting minimizes the initial current drag on the electrical supply system.

Repeated motor starts in a short period of time do not allow time for the heat generated from high starting currents to dissipate. For this reason, restart limits are sometimes imposed to limit how soon after shutdown a motor can be restarted.

8.7 Starting Circuits

8.7.1 General

Induction motors may be started with full supply voltage by connecting the motor directly to the supply circuit or with reduced voltage by temporarily inserting voltage reducers during the starting period. Motor controllers can be used for starting motors by either method and can be operated either manually or magnetically.

AC induction motors can be connected directly across the line without damage to the motor. However, because of the heavy current drag and voltage disturbance created on the supply system by the starting current, large AC motors are often started with reduced voltage.

A greater starting torque is exerted by a motor started on full voltage rather than reduced voltage. The available torque of an induction motor is proportional to the square of the applied voltage. Therefore, if the voltage is reduced to 80% of rated value during starting, the starting torque is reduced to 64% of maximum torque. The reduced voltage applied to the motor during the starting period lowers the initial starting current but also increases the period of acceleration time because of the reduced value of the starting torque. The type of load being started also has a bearing on the method of starting to be used. If, for example, a particular load might be damaged by sudden start-

ing and should be accelerated slowly, then reduced-voltage starting must be used.

AC motor controllers may use full-voltage/ across-the-line starters or reduced-voltage starters, which may be primary-resistor starters or autotransformer starters.

8.7.2 Full-Voltage Starters

Motors started on full-line voltage use across-the-line starters, which may be either a circuit breaker or a remote motor controller. A magnetically operated motor controller with an across-the-line starter is shown in Figure 8-9. The motor controller circuit is similar in purpose and operation to a circuit breaker control circuit, except that a line contactor is used in place of a circuit breaker. When the operating coil is energized by completing the circuit at the "start" pushbutton, the operating coil closes the line contacts for all three phases. Full line voltage is applied immediately to the motor. A "maintaining contact" is also closed by the operating coil, which allows the "start" pushbutton to be released while current is maintained through the operating coil to keep the line contacts closed. The operating coil will be deenergized by actuating the "stop" pushbutton or by actuation of an overload relay under excessive current conditions. When the operating coil deenergizes, the line contacts and maintaining contact open, deenergizing the motor.

8.7.3 Primary-Resistor Starters

In the primary-resistor starter, reduced voltage is obtained by adding resistances that are connected in series with each stator lead during the starting period. The voltage drop in the resistors produces a reduced voltage at the motor terminals. At some time after the motor is connected to the line through the resistors, accelerating contacts close and short circuit the starting resistors, applying full voltage to the motor (see Figure 8-10).

When the start button is closed, the main coil (M) is closed, closing all the M contacts and

connecting the motor to the line through the starting resistors. This causes the time delay coil (TD) to energize. After the time delay has elapsed, during which the motor has accelerated, the TD contact closes. This energizes the accelerating coil (A), which short circuits the starting resistors and applies full voltage to the motor.

In the starter just described, the starting resistance is cut out in one step. To obtain smoother acceleration with less supply system disturbance, starters are available in which the starting resistance is reduced in multiple steps.

8.7.4 Autotransformer Starters

Autotransformer starters, sometimes called starting compensators, may also be used to reduce the voltage applied to the motor during the starting period. Autotransformer starters may be either manually or magnetically operated; a typical manual type is shown in Figure 8-11.

The manual autotransformer starter is essentially a multipole, double-throw switch. In Figure 8-11, three rows of contacts are shown — the starting, running, and movable contacts. The starting and running contacts are stationary, and the movable contacts are attached to the operating handle. When the operating handle is moved to the start position, the movable contacts are moved against the starting contacts. This connects the wye-connected autotransformers to the line and the motor to the secondary side of the transformers. The magnitude of the secondary voltage of the transformers is determined by the tap setting of the transformer but is usually either 80% or 65% of the line voltage.

After the motor accelerates at reduced voltage, the operating handle is moved to the "run" position; this operation connects the motor directly to the line through the running contacts. The operating handle is held in the "run" position by the undervoltage device. If the supply voltage fails or drops to a low value, the handle releases and returns to the "off" position.

Chapter 8 Definitions

SLIP

- The ratio of the difference between the rotating magnetic field speed and the actual rotor speed to the rotating magnetic field speed. The speed of the rotating magnetic field is equivalent to the synchronous speed of the motor (determined by the frequency of the current and the number of poles of the motor). Slip is most frequently expressed as a percent of synchronous speed.

Table 8-1. Synchronous Motor Characteristics and Applications

Type designation	Synchronous, high speed above 500 rpm	Synchronous, low speed, below 500 rpm
HP range	25 to several thousand	Usually above 25 to several thousand
Starting torque (% of normal)	Up to 120	Low 40
Pull-out torque (%)	Up to 200	Up to 180
Starting current (%)	500 to 700	200 to 350
Slip	Zero	Zero
Power factor	High, but varies with load and with excitation	High, but varies with excitation
Efficiency (%)	Highest of all motors. 92% to 96%	Highest of all motors. 92% to 96%
Typical applications	Fans, blowers, DC generators, line shafts, centrifugal pumps and compressors, reciprocating pumps and compressors. Useful for power-factor correction, constant speed, and frequency changes.	DC generators and pumps. Useful for power-factor control and constant speed. Flywheel used for pulsating loads.

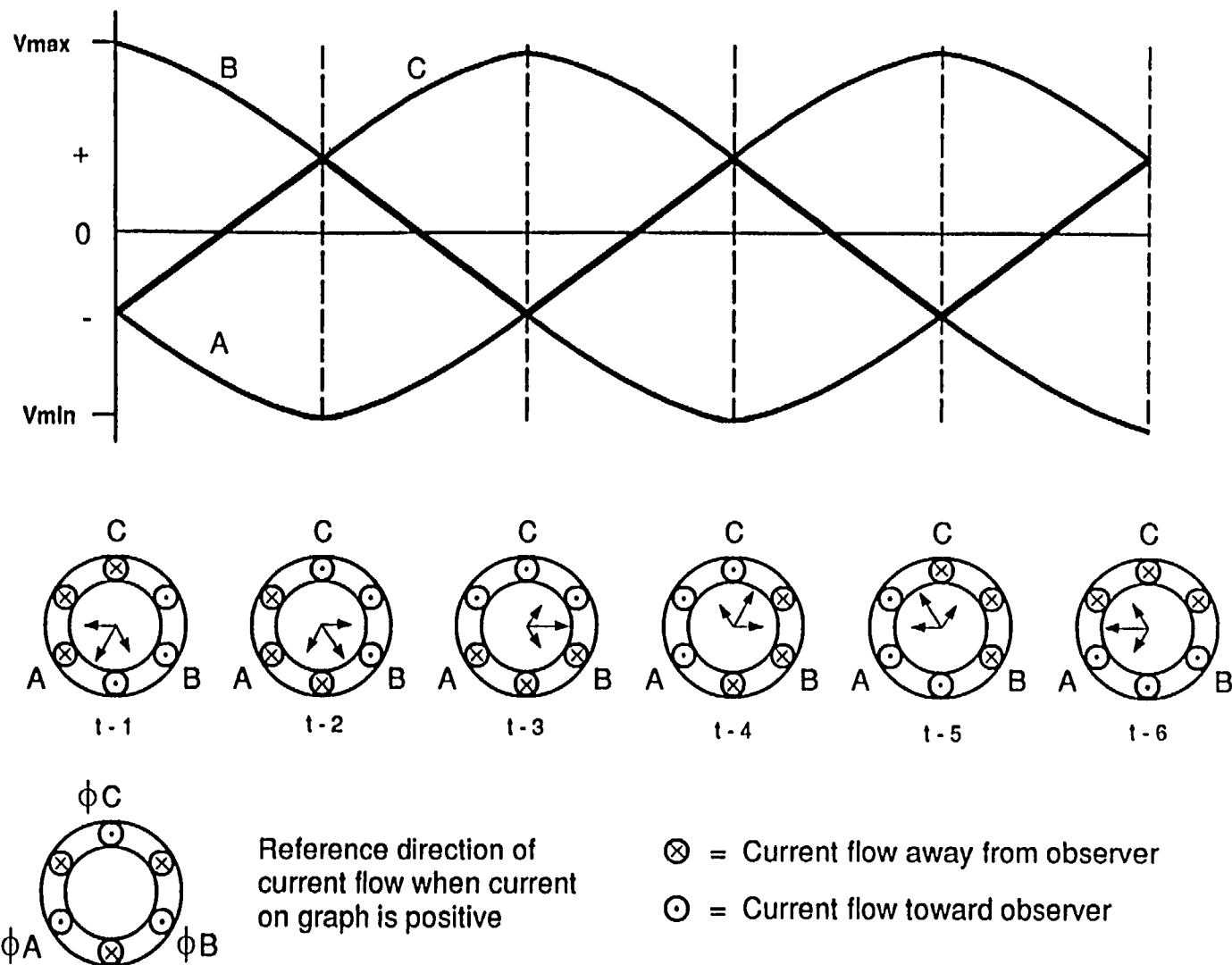
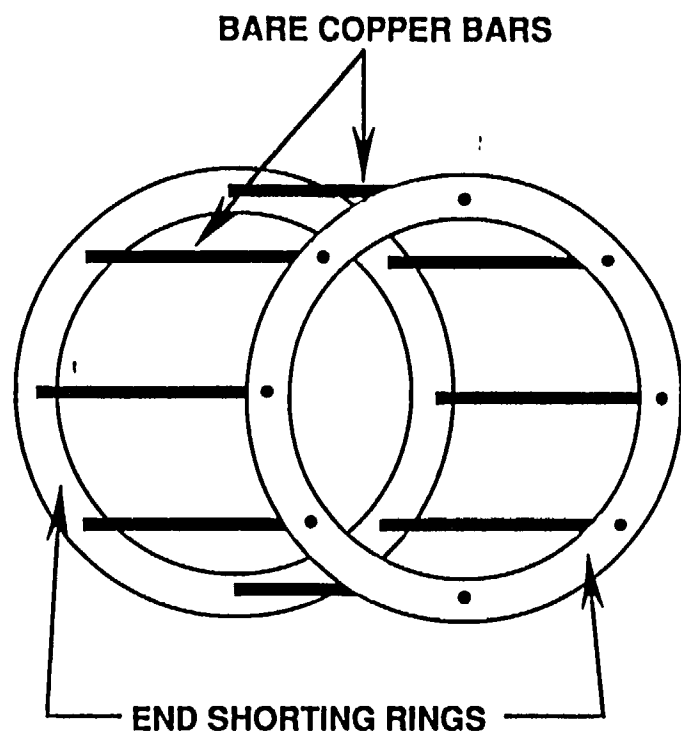
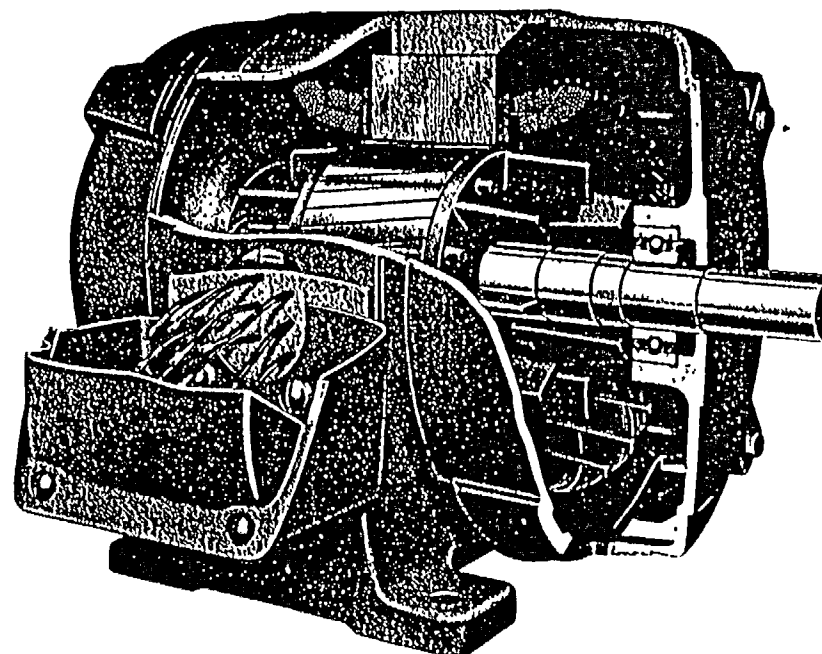


Figure 8 - 1. Development of a Rotating Field

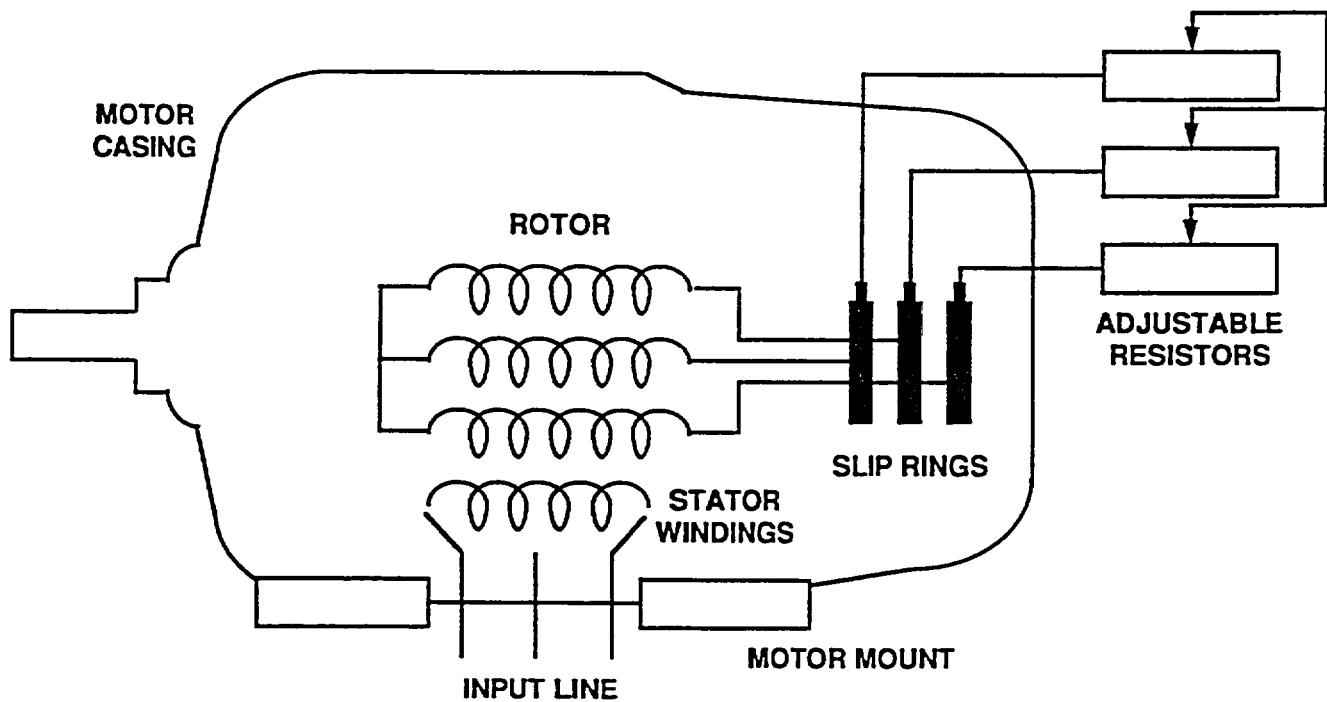


A. Simplified Squirrel Cage Rotor

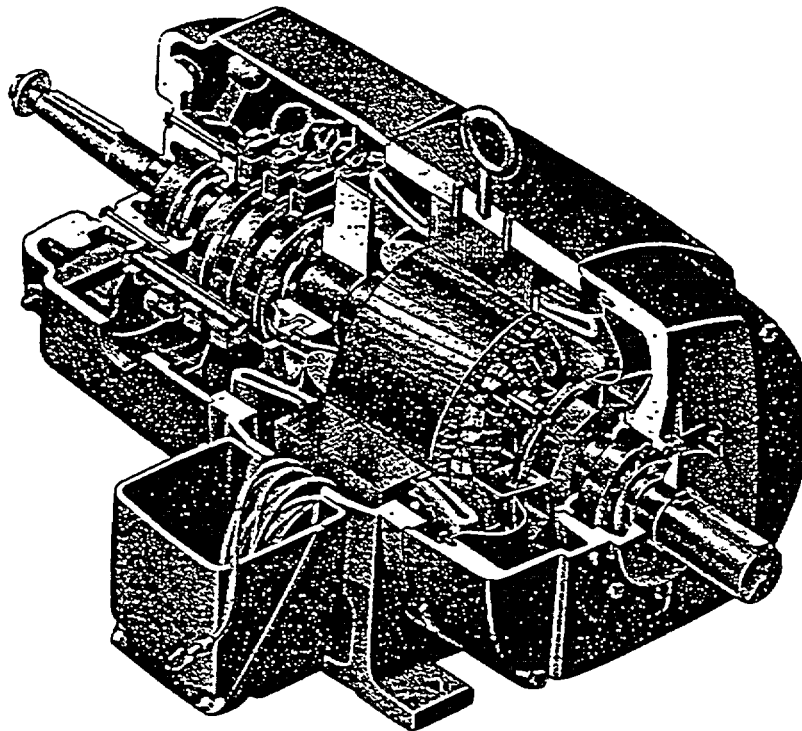


B. Cutaway View of an Induction Motor with Squirrel Cage Rotor

Figure 8 - 2. Squirrel Cage Induction Motor



A. Wound Rotor Motor Schematic Diagram



B. Cutaway view of Three-Phase Induction Motor with a Wound Rotor and Slip Rings Connected to the Three-Phase Rotor Winding

Figure 8-3. Wound Rotor Induction Motor

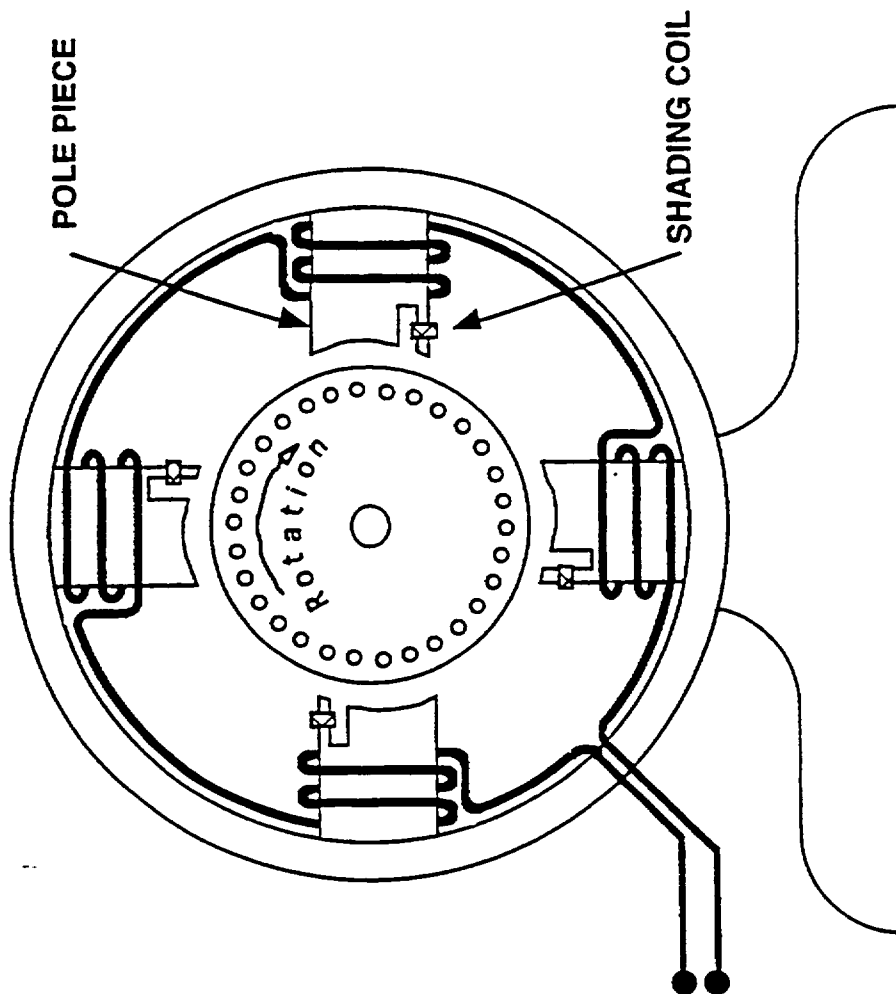


Figure 8-4. Shaded-Pole Single-Phase Motor

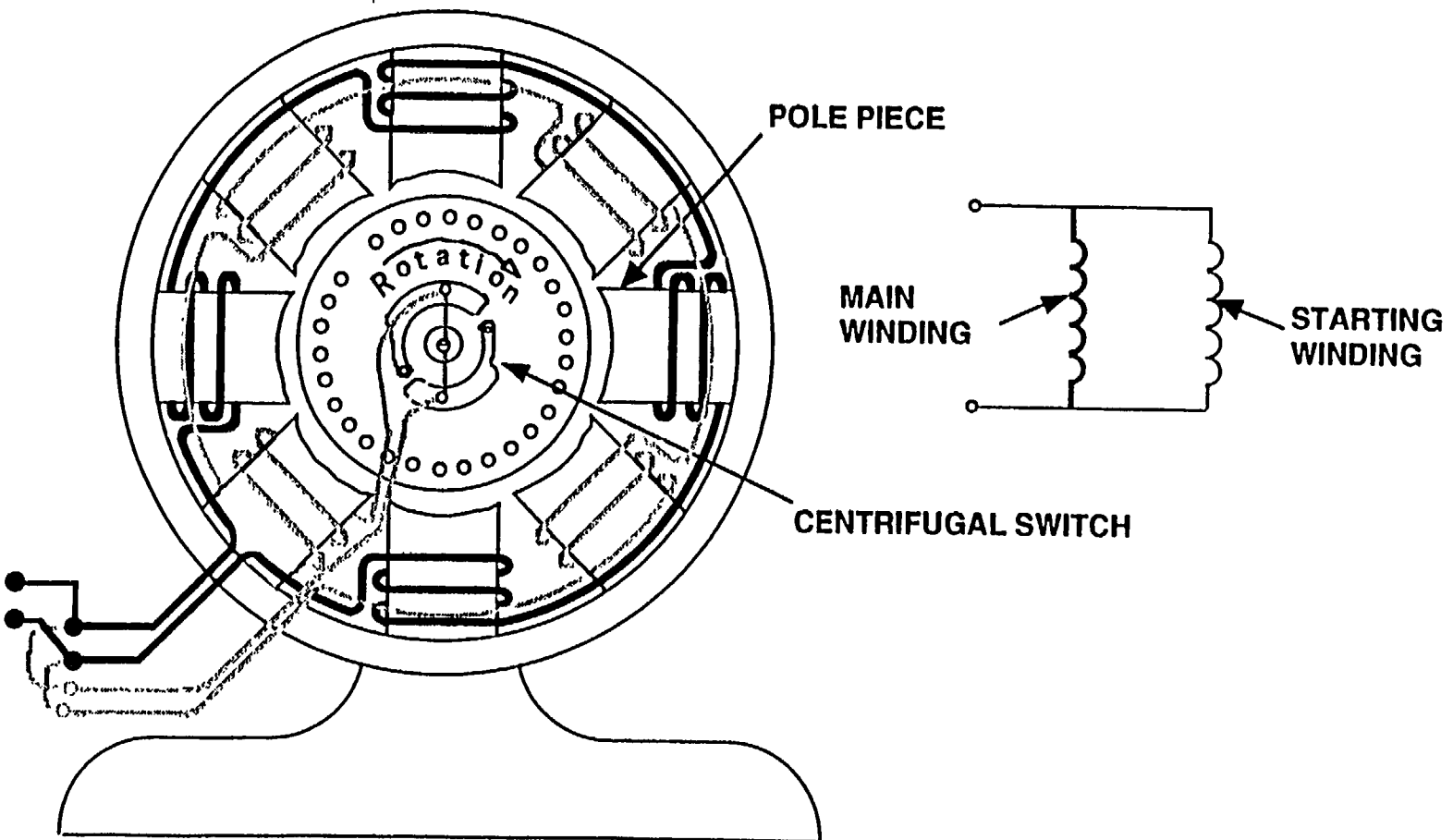


Figure 8-5. Induction-Start Single-Phase Motor

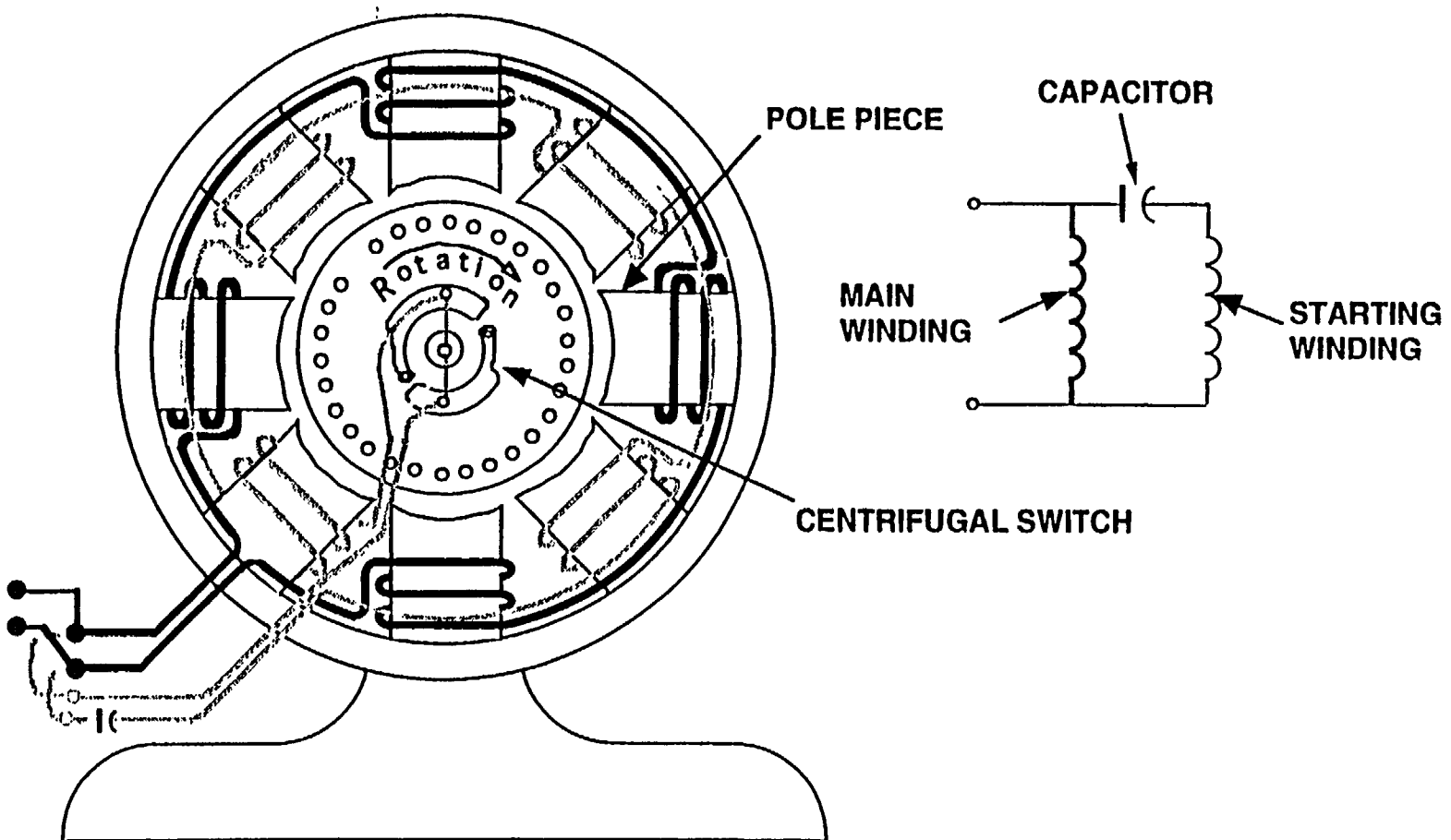


Figure 8-6. Capacitor-Start Single-Phase Motor

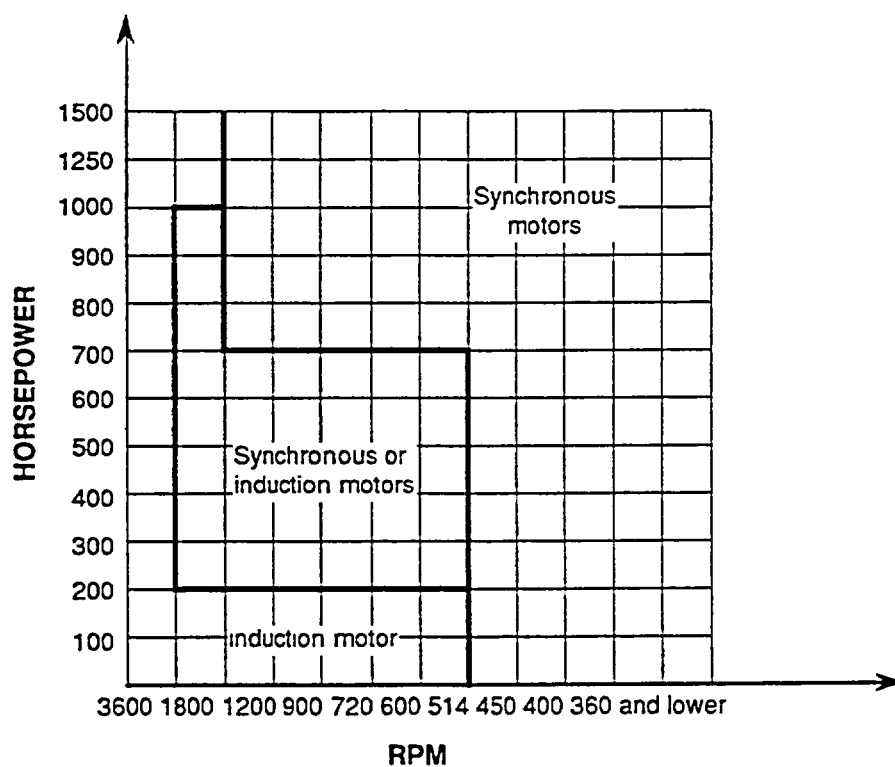


Figure 8-7. Indicating the General Areas of Application of Synchronous and Induction Motors

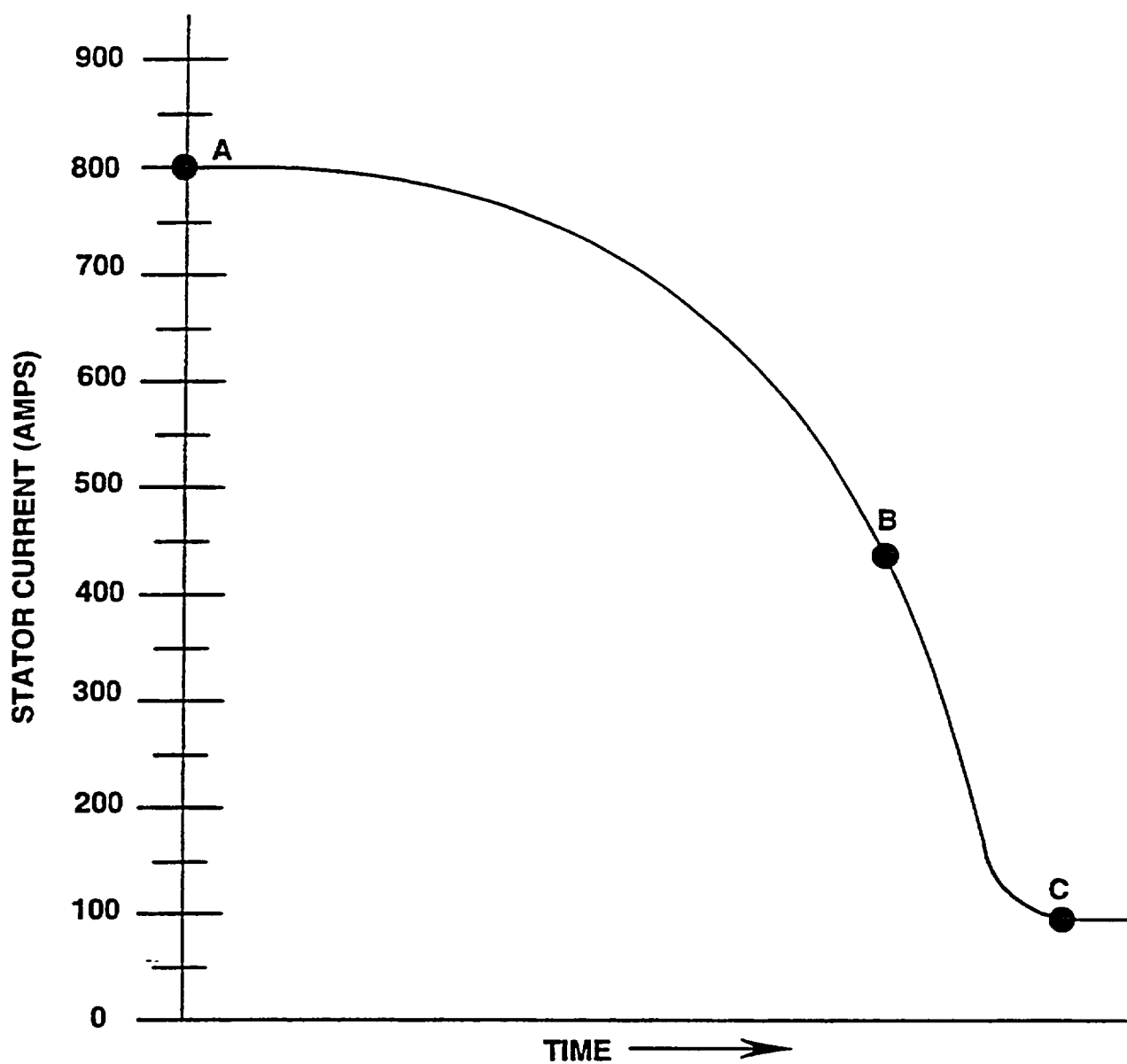


Figure 8-8. AC Motor Starting Current Curve

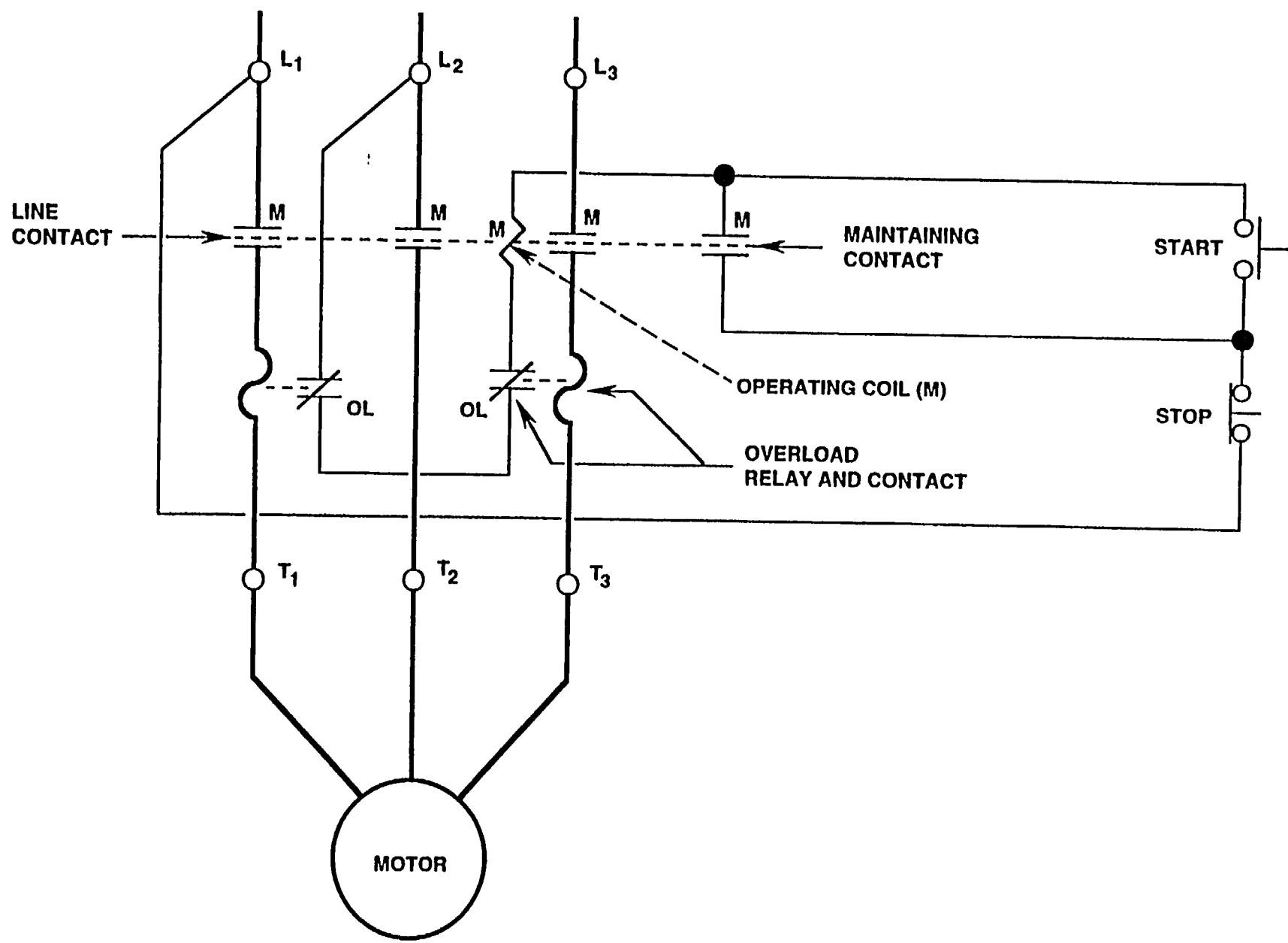


Figure 8-9. Magnetic Across-The-Line Starter

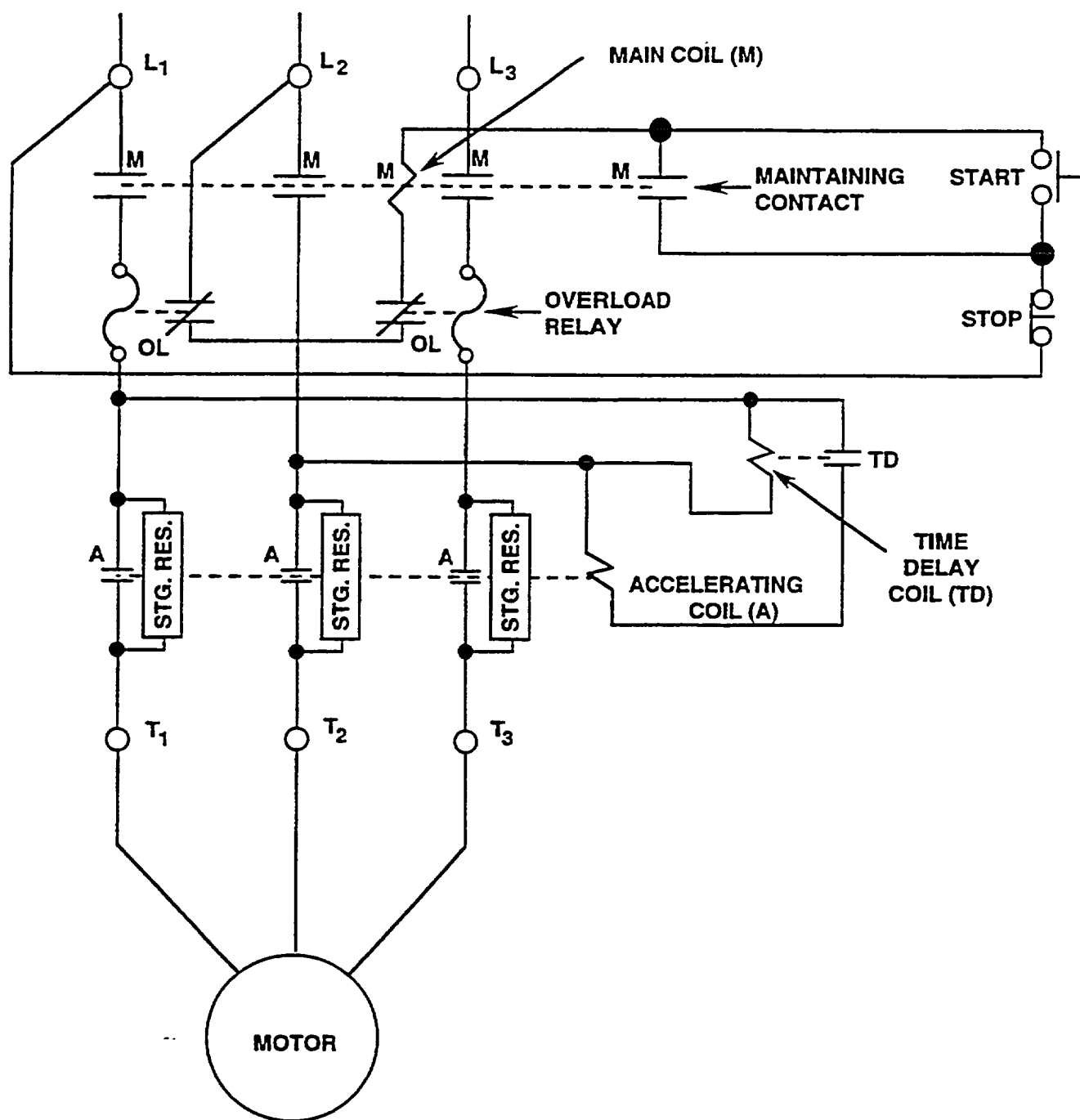


Figure 8-10. Primary Resistor Starter Diagram

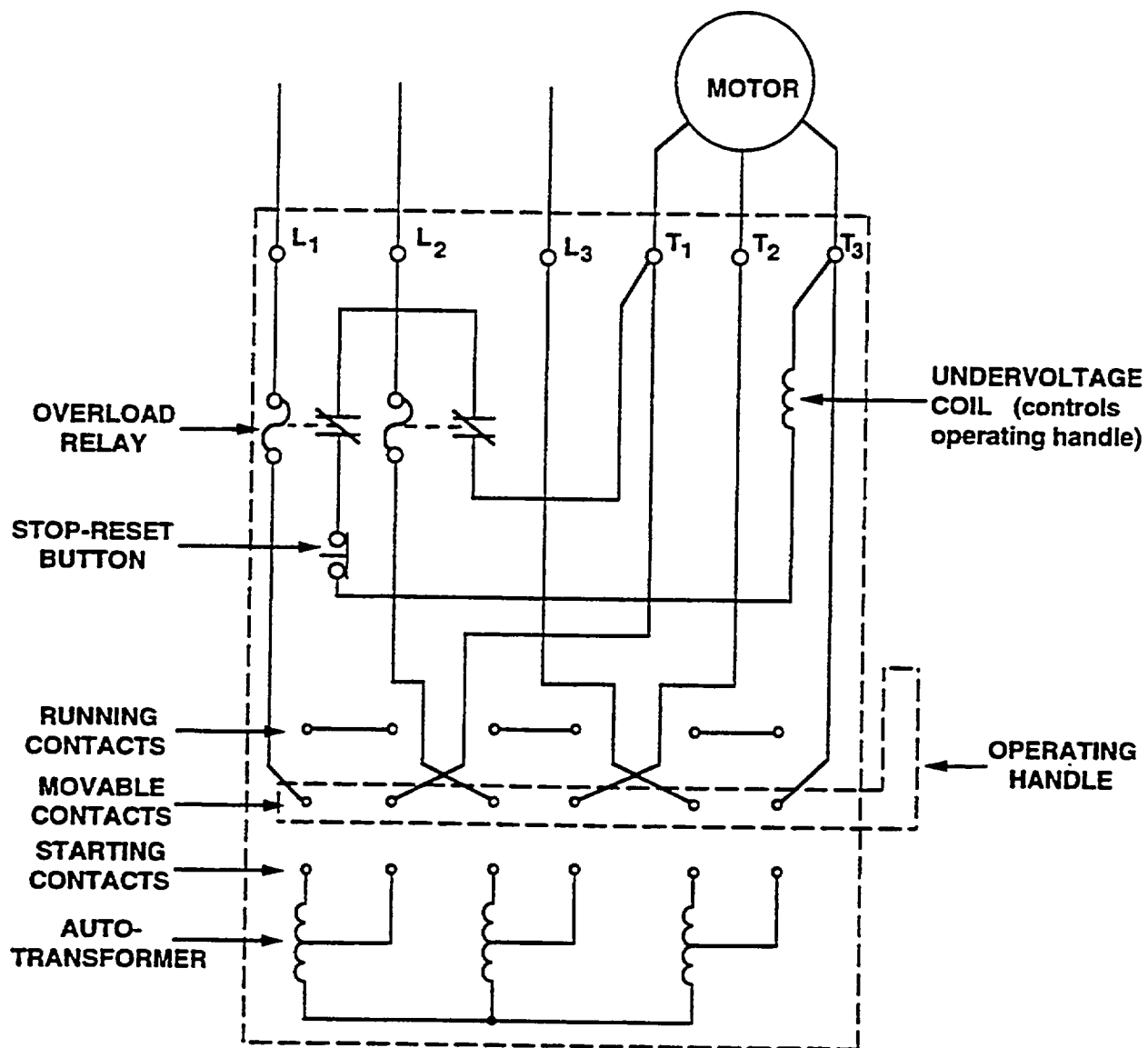


Figure 8-11. Autotransformer Starting Diagram

9.0 ELECTRICAL DISTRIBUTION EQUIPMENT

Learning Objectives

After studying this chapter, you should be able to:

1. Define and/or explain selective tripping and class 1E electrical components.
2. Briefly explain the terms redundancy and train separation.
3. Explain the difference between a shunt trip coil and an undervoltage trip coil in relation to tripping a circuit breaker.
4. Explain the need for extinguishing the arc during breaker operation.
5. Describe the attributes and applications of the following types of breakers:
 - a. Air circuit breaker
 - b. Oil circuit breaker
 - c. Air-blast circuit breaker
 - d. Vacuum circuit breaker
6. Describe the attributes and applications of the following devices:
 - a. Disconnect
 - b. Breaker control circuit
 - c. Protective relay
 - d. Fuse
 - e. Automatic bus transfer device
 - f. Uninterruptible power supply
7. Explain the operation of a lead-acid storage battery.
8. Explain why "load shedding" is necessary and how it is accomplished.
9. Explain why "load sequencing" is necessary and how it is accomplished.

9.1 General Discussion

The purpose of the electrical distribution equipment is to provide redundant, diverse, and dependable power to the many power plant loads, and to transport power from the main generator to the power transmission network. Power produced by the main generator or supplied from the transmission network is distributed to the various loads in the plant via conductors called buses. The term bus started out as a slang term for a conductor that could supply power to several loads. The term has gradually evolved to take on additional meanings. Most of the nuclear industry also uses the term bus to identify an electrical entity (such as a switchgear or circuit breaker enclosure) that is at a specific voltage and supplies power to several loads. The actual physical conductors within an electrical bus or switchgear enclosure are often called the busworks. Power supplied through the buses is controlled by switching or interrupting devices to protect, regulate, and route the electrical flow throughout the system. Switching and interrupting devices include the relays, fuses, and circuit breakers that provide the sensing and control mechanisms to manage the electrical distribution system.

The equipment and arrangements described in this chapter are simplified to show the general philosophy and practices in common use. Actual power plant use will depend on many variables outside the scope of this text.

Table 9-1 contains several terms, such as redundancy, that have specific meanings in relation to electrical distribution systems. The electrical distribution definitions of these terms are also provided in Table 9-1.

9.2 Generic Distribution System

The design of electrical power distribution systems varies considerably between commercial power plants and can be significantly different in the nomenclature used to designate components in the system, voltages used within the system, and

system layout. All plants are generic in the fact that they all contain:

- High voltage offsite distribution,
- High and medium voltage onsite distribution, and
- Low voltage control and instrumentation distribution.

The systems described in this chapter are not specific to any one plant.

9.2.1 Power Distribution Grid

The grid is a term used to describe the large-area high voltage transmission network or physical system used to generate and distribute electrical power to utility customers (see Figure 9-1). The utility has an obligation to maintain a reliable source of power at proper voltage and frequency. The load dispatcher fulfills this obligation by determining the grid power requirements and ensuring that the generating capacity matches that requirement. If a fault occurs on the grid, the load dispatcher and ground crews locate and minimize the power loss to that leg of the grid.

Distribution grids must provide continuous reliable service. Distribution grids have protective schemes that are planned and designed to ensure this service exists. A protective scheme is an arrangement of bus feeds, circuit breakers, circuit switchers, disconnects, fuses, and other protective and switching devices. Most protective schemes are designed to isolate a faulted line or section as close to the fault as possible, permitting the rest of the distribution grid to operate normally. A protective scheme that isolates a fault as close to the fault source as possible while still protecting the distribution system from damage is called selective tripping (see Table 9-1). A selective tripping protective scheme is designed according to three rules:

- (1) The closest protective device to the fault shall operate first;

- (2) Selectivity of response time is provided; and

- (3) Response time is permitted to vary with the severity of the electrical problem.

With these factors built into a protective scheme, outage areas are minimized and rapid reestablishment of power is possible. It is easier to locate a fault if the closest bus or line is known.

Figure 9-2 shows a simplified distribution system or grid that supplies power to a residential home. The cord running from the TV set to the wall outlet has been broken and shorted to ground. If no protective devices existed on the line, the resulting large current could cause a fire in the house and possibly damage the individual pole transformer for the house or the 18-kV/6900-volt pole transformer that supplies the rest of the neighborhood. This sequence of events is prevented by a selective tripping protective scheme. For the TV cord the individual branch breaker in the house should trip first and isolate the fault. If current should rise too quickly (or if the individual breaker should fail to open the circuit), the household's main feeder breaker should trip. If the main feeder breaker cannot open in time to protect the upstream (toward the generator) buses, the fuse on the individual household's pole transformer should blow. The next line of defense should be the fuse on the neighborhood pole transformer. For a fault to affect this much of the distribution system it would have to draw a very high current in a very short amount of time. The protective devices, shown in Figure 9-2, are progressively harder to trip (take more fault current) as the power source is approached. This arrangement corresponds to the three selective tripping protective scheme rules.

If, instead of the grounded TV set cord, the 18-kV grid line fell and became grounded, the first line of defense would be the 138/18-kV substation transformer breaker. There are many devices and schemes to protect the 345-kV transmission system and the lower voltage distribution systems, but their specifics are beyond the scope of this

course. The philosophy used for the design of these devices still follows the selective tripping rules discussed.

The same philosophy used in protective schemes for the grid applies to in-plant power distribution (see Figure 9-3). If a fault occurs in the A cooling lake pump motor, breaker G should trip first to protect the rest of the distribution system. This action would allow the B cooling lake pump to substitute for the faulted A pump and no required services would be lost. If the G breaker does not open in time to protect the upstream buses, the F breaker or B breaker must trip to protect the rest of the distribution system. The plant can probably operate for a while without Bus 20 (or either cooling lake pump) until the fault can be found and corrected. If neither the F nor B breaker opens in time for adequate protection, the A breaker must open to protect the distribution system. The trip of breaker A and the consequent loss of Bus 24 may cause the plant to trip, but the main transformer will have been isolated from the fault, and the maximum amount of the 345 kV grid will have been protected.

9.2.2 Switchyard Bus Arrangements

Buses are a necessary part of generating stations or factories with large electric power distribution systems. Common switchyard bus voltages are 22 kV, 161 kV, 235 kV, 345 kV, and 500 kV. Many internal plant bus circuits operate at lower voltages (usually 4160 or 6900 volts). Transformers located throughout the plant further reduce the voltage to supply electrical power to lower voltage motors and electrical equipment. The arrangement of a bus system is determined by plant needs. A few bus arrangements are discussed below.

To reduce the loss of equipment during bus maintenance, the main bus may consist of several bus sections. These separate sections are usually provided with bus-tie circuit breakers to tie or split the bus (see Figure 9-4). A bus-tie breaker arrangement like the one shown in Figure 9-4 is

sometimes called a "breaker-and-a-half" arrangement because there are three breakers for the two loads that come off each bus-tie between the north and south bus. This arrangement allows isolating any one load while retaining power to all remaining loads.

9.2.2.1 Parallel Bus

In some installations, redundant load power is provided by a set of parallel buses with interconnecting circuit breakers. The parallel bus arrangement provides a "complete spare" capable of handling full load capacity. Both sets of equipment are usually kept in service at all times so that should either one fail, no interruption occurs to the connected facilities. A parallel bus system is shown in Figure 9-5. The major disadvantage of this design is expense. However, for loads that require highly reliable power, the parallel bus arrangement is ideal. (Note that Figure 9-5 shows a switchyard for a two-generator facility with a breaker-and-a-half bus-tie breaker arrangement.)

9.2.2.2 Ring Bus

To approach the reliability of a parallel bus arrangement yet keep the cost to a minimum, switchyard buses are sometimes arranged in a ring bus (see Figure 9-6). Instead of circuit breakers to disconnect each line (as in a parallel bus arrangement), lines are placed on the ring bus directly. The ring bus is divided into sections by ring bus circuit breakers. Each separate section can be disconnected without interruption to the other sections.

9.2.3 Electrical System Design Requirements

The basic requirement for the design of nuclear power plant electrical distribution systems is provided in General Design Criterion 17 from 10 CFR 50 Appendix A. Criterion 17 is quoted below, in part:

"The onsite electric power supplies, including the batteries, and the onsite electric distribu-

tion system, shall have sufficient independence, redundancy, and testability to perform their safety functions assuming a single failure.

Electric power from the transmission network to the onsite electric distribution system shall be supplied by two physically independent circuits designed and located so as to minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. A switchyard common to both circuits is acceptable. Each of these circuits shall be designed to be available in sufficient time following a loss of all onsite AC power supplies and the other offsite electric power circuit, to assure that specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded. One of these circuits shall be designed to be available within a few seconds following a loss-of-coolant accident to assure that core cooling, containment integrity, and other vital safety functions are maintained.

Provisions shall be included to minimize the probability of losing electric power from any of the remaining supplies as a result of, or coincident with, the loss of power generated by the nuclear power unit, the loss of power from the transmission network, or the loss of power from the onsite electric power supplies."

Four essential requirements are derived from Criterion 17.

- The onsite electrical distribution system must have at least two separate parts, either of which is capable of providing power to all components required for safe functioning of the reactor.
- The two parts of the onsite distribution system must be sufficiently separated to preclude the loss of both parts if one part

should suffer a loss of power or severe fault, such as a bad ground or short circuit.

- The onsite distribution system shall be provided with two independent power supplies from the offsite transmission network that are promptly available after a loss of all onsite AC power supplies (one offsite supply shall be available within a few seconds). Many nuclear plants operate with the offsite power supply continuously in use for safety-related loads, while other plants have a fast-transfer capability to satisfy this requirement.
- Both of the two separate onsite parts shall have a backup power source available within a few seconds following a loss of coolant accident or loss of offsite and onsite power supplies.

9.2.4 Offsite (Preferred) Power Connections

The offsite (preferred) power system includes two or more identified power sources capable of operating independently of the onsite or standby power sources and encompasses the grid, transmission lines (overhead or underground), transmission line control systems, switchyard battery systems, and disconnect switches, provided to supply electric power to onsite safety-related and other equipment.

The offsite power connection is called the preferred source of power for onsite safety-related loads. The main generator may be used to supply power to some or all onsite safety-related loads during normal operations, but the switchyard system must include the capability for a fast transfer of these loads from the generator to an offsite power connection in the event the main generator supply is lost.

9.2.5 Onsite Power System Terms

Class 1E is the safety classification term given to safety-related electrical equipment and systems

that are essential to emergency reactor shutdown, containment isolation, reactor core cooling, and containment and reactor heat removal, or are otherwise essential in preventing significant release of radioactive material to the environment. Essentially, all electrical equipment associated with safety-related systems must be designated Class 1E.

During shutdown and accident conditions, which is when the majority of the Class 1E loads are operating, the main generator is not available. Therefore, it is not considered part of the offsite (preferred) power system. The offsite (preferred) power source is the two or more connections made to the system grid for supplying power to the plant Class 1E loads. The components comprising the offsite (preferred) power sources at nuclear facilities are arranged to provide sufficient independence (both physical and functional) to minimize the likelihood of simultaneous outages of both circuits.

Figure 9-7 shows one arrangement for supplying power to the Class 1E loads. Normally the safety-related 4160V buses (34C and 34D) are powered from the non-safety 4160V buses (34A and 34B) through the bus-tie breakers. If the supply through the normal station service transformer (4 NSST) is lost, the bus-tie breakers will trip open and the breakers from the reserve station service transformer (4 RSST) to the safety buses will automatically close to effect a fast transfer of the power source. Some plants with similar arrangements keep the safety buses continuously powered from the offsite (grid) source and use the main generator source only for limited time periods when necessary maintenance must be performed on the RSSTs. In either arrangement, the emergency diesel generators (EDGs) provide the backup power source for the safety buses in case the fast transfer does not work properly or offsite (grid) power is lost. Note that the two separate off-site power sources (two tie-ins to the 345kV grid) and the two EDGs satisfy two of the essential requirements of General Design Criterion 17.

Total functional independence between the two offsite power sources is not maintained in the switchyard itself because all the bus sections are normally electrically connected. However, in the event of an electrical fault, electrical separation of bus sections can be established in a few cycles by circuit breaker operation. The fault isolation and bus transfer scheme is designed to permit automatic fault isolation while still maintaining two connections from the plant to the grid. Therefore, both independent circuits connecting to offsite (preferred) power will remain energized unless the fault is on one of them, in which case the other independent circuit will remain energized and unaffected.

Understanding the concept of electrical redundancy requires a familiarity with the term "train," which is another slang term used in electrical distribution parlance. A train is a combination of buses, switchgear, and components which ultimately receive power from the same major plant service (high voltage) transformer. All nuclear plants have either two or three separate power trains, each of which is powered from its own major transformer, and is, therefore, separate and distinct from the other power train(s). Separate trains may be designated by numbers, letters, or colors, and each train will encompass some buses at all voltages used within the plant. The primary characteristic of any train is that it is kept separate and distinct from the other train(s).

Figure 9-7 illustrates the concept of redundancy (see Table 9-1). In this plant there are two separate electrical trains: the left side "A" train including bus 34C, and the right side "B" train including bus 34D. Each train has two offsite power connections and its own diesel generator backup power supply. Recall from the Plant Cycles chapter that all safety systems must have at least two of each important component, such as pumps, valves, piping loops, etc. Redundancy is achieved by having the like components electrically separated so that in each safety system one component is on one electrical train and the redundant component is on the other train. The compo-

nents on each safety train must be capable of performing all functions required for the safety of the reactor, *with the other train deenergized*. Electrical redundancy in a nuclear plant means that either train of the electric distribution system can be lost or faulted, and the safety-related components on the other train can perform all functions required for reactor safety. This objective is achieved in the example plant shown in Figure 9-7 by having half the safety system components powered from the A train and the other half of the safety system components powered from the B train. Redundancy satisfies one of the essential requirements of General Design Criterion 17:

(Please note: The terms bus and train are vernacular or slang. Some facilities use the general term bus interchangeably with train, but most of the nuclear industry uses the terms bus and train as defined in this chapter. The specific meanings of these two slang terms, bus and train, are often confusing to new plant operators).

Another electrical distribution term, also illustrated on Figure 9-7, is train separation (see Table 9-1). Note that there is no bus-tie breaker between bus 34C and bus 34D. Recall that one of the essential requirements of General Design Criterion 17 is that the two parts (trains) of the distribution system must be sufficiently separated to preclude the loss of both parts should one part suffer a severe fault. If there were a bus-tie breaker between bus 34C and bus 34D, and that breaker suffered a severe short to ground such that the breaker was unable to trip open due to the high current, both trains would be faulted. In addition, neither train could be energized until the faulted breaker could be physically disconnected from the two trains. In the meantime there would be no safety function capability, and the reactor would be unprotected from a major accident. To preclude this scenario, nuclear facilities adhere to the policy of train separation, meaning that there are no electrical (or physical) connections between the two safety electrical trains. Some nuclear facilities have components that can be powered from either safety train, but an extensive interlock

system is used to ensure that the component is fully disconnected from one train before it is connected to the other train. (Please note: Many facilities may refer to their safety electrical trains by colors or numbers rather than A and B, but the concepts are the same. The two trains carry redundant safety loads and are electrically separated, each with two connections to the offsite power grid, and each with a diesel generator backup power source.)

9.2.6 Vital and Nonvital Subsystems

The onsite power system shown in Figure 9-8 illustrates an electrical power system that is separated into vital (safety-related) and nonvital distribution subsystems. The loads supplied by the nonvital subsystem are loads that are not required to place the reactor in a safe shutdown condition or prevent the release of radioactivity to the environment. Such loads include components in the turbine building, switchyard, and administrative building.

The vital distribution subsystem includes a medium voltage (4160V) vital bus, the low voltage motor control centers, and an EDG. As discussed in section 9.2.5, the vital loads are separated onto two redundant safety electrical trains; only the A train is shown in Figure 9-8. The A electrical train has access to two offsite (preferred) power supplies and an onsite (backup) power supply (the EDG). Source selection is accomplished by automatically transferring from the nuclear unit source (main generator), to the offsite source, to the backup source, in that order. The reverse transfers are normally done manually.

As previously discussed, the distribution buses, motor control centers, and transformers comprising the A train are arranged to provide physical independence and electrical separation from the B power train. The A safety train also has a DC bus and battery associated with it. These components will be discussed in more detail later in this chapter.

9.3 Switchyard Connection Components

This section discusses three types of components that are usually found in nuclear plant switchyard connections and may also be found elsewhere in the distribution system. The three components are: transformers, bus ducts, and disconnects.

9.3.1 Switchyard Transformers

Electric utility grids normally operate at 235kV, 345kV, or 500kV. Nuclear plant main generators normally generate power at 22.5kV. The large motors used to drive reactor coolant pumps, feed pumps, condensate pumps, and circulating water pumps sometimes use 13.8kV, but 6.9kV or 4160V is used for these motors at most plants. The emergency diesel generators at most nuclear plants generate power at 4160V and most safety pump motors use 4160V or 480V. Transformers must be used between all these different operating voltages.

The switchyard transformers used to transform the grid voltage to plant voltages are normally large outdoor structures that use special oil as a coolant around the conductor coils. The oil is normally circulated through the transformer cores to remove the heat of electrical current flow, and then through finned tubes where the heat is transferred to air circulated by multiple self-contained fans. The fans are automatically controlled to maintain a specific oil temperature range.

9.3.2 High Voltage Buses and Bus Ducts

Power from the main transformer is connected to the switchyard via transmission lines at high voltages (345kV, 500kV,...). Power from the normal station service transformers to the in-house loads is delivered via buses. The buses, usually made of copper or aluminum, are specially designed conductors in the form of a tube or bar. Buses that transport high voltages through the plant are normally supported by a protective housing or enclosure called a bus duct (see Figure 9-9).

The bus duct may be made of insulating material or metal that is insulated from the high voltage bus within.

9.3.2.1 Isolated Phase Bus Ducts

The main generator output buses are connected by means of isolated phase (isophase) bus ducts to the main and normal station service transformers (see Figure 9-9). The isophase bus ducts originate at the high voltage terminals (22kV) of the main generator and terminate at the primary terminals of the main or service transformer. The use of isophase bus ducts, one duct for each of the three generator phases, provides physical separation of the three phases to prevent phase-to-phase faults. A forced air cooling system is normally used to cool the volume within each isophase duct to carry the electrical current flow heat away from the bus.

9.3.2.2 Protective Bus Ducts

Inside the plant, much high voltage electricity is carried and distributed by buses in protective bus ducts. The bus duct consists of a metal or nonconductive housing that supports, encloses, and insulates the copper or aluminum bus bars within. In Figure 9-9 auxiliary transformer output is delivered to the switchgear cubicle via protective bus ducts. (Metal housings that contain electrical buswork and circuit breakers are called cubicle switchgear or simply switchgear. Buswork is the term used for the metal bus bars inside the switchgear that connect power to (or from) the circuit breakers mounted in the switchgear.) High voltage and emergency (vital) switchgear is normally connected by bus ducts. Nonvital and low voltage switchgear is connected with electrical cables.

9.3.3 Disconnects

A disconnect is a piece of conductor that can be easily removed from the circuit (and subsequently replaced) like a removable link. An electrical circuit symbol for a disconnection is shown

in Figure 9-5. The purpose of a disconnect is to provide an additional, inexpensive way of isolating equipment. Disconnects are *not* used to interrupt circuits under load. The operating action of a disconnect is very slow when compared to a breaker. If a disconnect were opened under load, it would cause severe damage to the disconnect and possible injury to the personnel operating the disconnect. A typical use of a disconnect is to isolate equipment, such as a large transformer or breaker. This is done by installing a disconnect in series on either side of the equipment or breaker. The breakers associated with a disconnect must be open to isolate the power source or load before the disconnect can be opened (or reclosed).

Switchyards have very elaborate disconnects because of the higher voltages that are encountered. These disconnects are usually found throughout the grid network. Higher voltages require a larger gap to ensure isolation, and more insulation from adjacent structures. Switchyard disconnects are usually operated by insulated levers or gear mechanisms at a convenient location. The lever may be operated manually or by a motor. The latter type of disconnect is called a motor-operated disconnect (MOD).

9.4 Circuit Breakers and Breaker Control

Circuit breakers are current interrupting devices used to supply current to appropriate loads, and protect circuits from an overload or other fault. A circuit breaker consists of a set of contacts held closed by a mechanical latch. If an electromagnet or a thermal bimetallic strip generates enough force to unlatch the breaker, large tension springs rapidly force breaker contacts apart and the circuit is opened. For the operating mechanism shown in Figure 9-10, the breaker is initially shut by energizing the closing solenoid, which pushes upward, causing the operating linkage to be straightened out. Heavy springs are stretched and the trip latch keeps the breaker closed. If too much current is sensed, the solenoid trip coil is energized. Its core plunger is pushed out of the solenoid, releasing the trip latch. The large springs

snap the circuit breaker contacts open, and the circuit is interrupted. A trip coil that is energized to trip is called a shunt trip coil. A trip coil that is deenergized to trip is called an undervoltage trip coil. Some breakers, such as reactor trip breakers, may have both a shunt trip and an undervoltage trip for redundancy/reliability.

When contacts of a switch or breaker separate with current through them, an arc develops. (An electrical arc is the passage of electrical current through an air gap between partially separated contacts.) Air at room temperature is a good insulator and will withstand relatively high voltages without permitting the passage of current. However, when air is heated to a few thousand degrees, air molecules become highly agitated and electrons from these atoms are easily freed to carry an electric current. When contacts of a breaker first separate, only a thin layer of cool air exists between the contacts. Even a moderate voltage between the contacts is enough to overcome the resistance of the thin layer of air and current will start to flow, forming an arc. The current flow rapidly heats the air between the contacts to extreme temperatures (9000° to 45,000°F in some high voltage breakers). The high air temperature ionizes the air, lowers the air resistance, and allows current flow to continue across the gap between the contacts. Eventually, the contacts move far enough apart that the air resistance becomes too great to sustain the arc. The arc extinguishes and the circuit is open.

To prevent circuit breaker damage due to the high temperatures, circuit breaker designs must include features that rapidly extinguish or dissipate the arc. Also, rapid extinguishment of the arc stops the current flow to the load promptly, which was the original intent of opening the breaker.

To interrupt a DC circuit successfully, the circuit breaker must open far enough that the voltage required to maintain the arc is greater than the voltage existing between the open contacts.

Interruption of an AC circuit is different from

interruption of a DC circuit. In a purely resistive AC circuit, current and voltage are in phase. Therefore, the arc will quickly be interrupted when voltage passes through zero. The gap between the breaker contacts must then be large enough in the next alternation to prevent reestablishment of the arc.

Most AC loads are both resistive and inductive. Interrupting an inductive load presents a greater problem than interrupting a purely resistive load. With an inductive load current lags voltage to some degree. Therefore, current continues to flow during the time that applied voltage passes through zero. When current finally passes through zero, applied voltage will again exist. The lagging current tends to prolong the arc. This process is referred to as inductive kick. Therefore, the contacts in a circuit breaker installed in a normal AC circuit with inductive loads must open farther and/or faster to extinguish the arc.

9.4.1 Air Circuit Breakers

Of the many circuit breaker designs that exist to extinguish the arc produced by a breaker trip, the air circuit breaker (ACB) is the simplest. An ACB relies upon the air between the contacts to extinguish the arc and to open up the circuit. ACBs are used extensively in low and medium voltage applications, such as switchboards, switchgear groups, and distribution panels. In some medium voltage ACBs, a short puff of air is used to help extinguish the arc (see Figures 9-11 and 9-12).

Most modern ACBs are called stored energy breakers and are rapidly closed by cam and spring arrangements rather than the relatively slow solenoid closing operation shown in Figure 9-10. A pictorial representation of a cam-operated breaker sequence is shown in Figure 9-13. A breaker using the cam operation shown in the figure is designated as a stored energy breaker because a charging motor or lever-operated ratchet mechanism is initially used to rotate the heavy cam into the crossover or ready position as shown in part A. At the crossover point the strong closing spring is

fully stretched and poised to snap the cam all the way around. A spring retention pin is normally used to hold the cam in this semistable equilibrium position until the breaker is required to be closed. When the spring retention pin is released by a closing signal, the strong spring snaps the cam the rest of the way around to rapidly close the contacts.

The contacts are opened by another set of springs (the tripping springs) attached to the contact arm. These springs are stretched into tensile stress when the contacts are closed. Another retention device, called the tripper bar, holds the contacts closed against the tripping springs until an opening (trip) signal is received. The opening (trip) signal releases the tripper bar, which allows the tripping springs to pull the contacts open (apart). Once the breaker is open, the charging motor or manually operated lever can be used to rotate the cam into the ready position again (thus "charging" the closing spring) in preparation for repeating the cycle.

9.4.2 Air-Blast Circuit Breakers

Air-blast circuit breakers are commonly used for indoor high-voltage operations above 15 kV (see Figure 9-14).

In the air-blast breaker, a control circuit signal opens a magnetic valve and admits compressed air to the top of a piston for the opening operation. As the piston moves downward, a mechanical linkage pulls back the contact arm, opening the contacts and drawing an arc. At the same time, the linkage opens the air blast valve, and compressed air is released through the blast tube directly into the arc path. As the contacts part, this blast of air carries the arc up through the arc splitter and into the arc chute where it is extinguished. The arc gases are cooled before they pass out into the atmosphere. When the contacts have opened enough to ensure an open circuit, the blast valve closes.

To close the breaker, the lower magnetic valve admits compressed air to the bottom of the piston, which closes the contacts at high speed. Air

storage capacity provides two close-and-open operations before more air is needed (depending on design). A pressure switch prevents operation of the breaker if air pressure falls below the set value for opening or closing.

Some switchyard gas blast breakers use sulfur-hexafluoride (SF-6) instead of compressed air. SF-6 has better arc extinguishing characteristics than compressed air. The SF-6 circuit breaker works very much like the compressed air breakers. A high pressure reservoir of gas is maintained in readiness and when the main contacts of the breaker part, a stream of high pressure gas is directed into the arc path to cool and extinguish it. The SF-6 gas is not exhausted to the atmosphere as the air is in the compressed air breaker. Instead, the SF-6 gas is recycled into a low pressure sealed tank.

9.4.3 Oil Circuit Breakers

Oil circuit breakers (OCBs) are used for outdoor high-current or high-voltage duty. OCB contacts are submerged in oil and interrupt the current under oil. Oil is a much better coolant and insulator than air.

The "dead tank" breaker is the most common type of OCB used for voltages above 13.8 kV. The name "dead tank" comes from the fact that the tank is at ground potential and insulated from the energized parts by oil. The actuating device (operator) is located outside the tank and moves a vertical actuator rod through a mechanical linkage (see Figure 9-15).

The dead tank breaker has two sets of contacts, the make-and-break bayonet contacts and the main contacts. The make-and-break contacts open and close inside the arc chamber. The arcing takes place inside this chamber when the contacts are opened or closed. When the make-and-break contacts are closed, low resistance contact is made between the make-and-break bayonet contact and the stationary or tulip contact. The main contacts close immediately after the make-and-break contact and open immediately before them, thus car-

rying most of the current; however, no arc is drawn because contact has already been made by the make-and-break contact.

In the oil circuit breaker, the arcing takes place between the top of the make-and-break contact and the tulip contact. An arc chamber is provided to contain the arc.

As the make-and-break contacts move downward, an arc is drawn. The arc produces a high-pressure bubble in the oil that keeps down arc energy. As the contacts enter the throat passage of the arc chamber, turbulent oil surges against the arc and extinguishes it. High gas pressure from the arc forces oil through the arc path. Complete withdrawal of the make-and-break contacts lets the gas bubbles escape, and oil refills the arc chamber.

9.4.4 Vacuum Circuit Breakers

Vacuum circuit breakers (see Figure 9-16) provide another method of interrupting a circuit and is growing in popularity, particularly in the primary distribution voltage range. The principles of vacuum interruption are quite different from gas or oil breakers.

The contacts of a vacuum breaker are enclosed in a ceramic envelope or "bottle" that is evacuated to an extremely low atmospheric pressure, approximately .0023 in. Hg absolute. Although the physics of interruption are quite complex, the vacuum interrupter works because the arc requires a conducting path to sustain it. Within the vacuum bottle there are no gasses to ionize; therefore, for all practical purposes, there can be no conducting path and the arc cannot be sustained. Figure 9-15 shows a cutaway view of a single pole vacuum interrupter. This device, deceptively simple in appearance, has a stationary contact firmly mounted on one end of the enclosure. The moving contact, which travels a very short distance from open to close (1 inch), is sealed to the other end of the envelope with a flexible metal bellows.

Although the technology of design and manufacturing of the vacuum interrupters is extremely complex, circuit breakers using these devices are very simple in operation. They require only lightweight mechanisms to close and open the contacts, which are quite different from the massive mechanisms required for large oil and gas type circuit breakers.

9.4.5 Breaker Control

A simplified wiring diagram for an ACB breaker control circuit is shown in Figure 9-17. Power for this control circuit is supplied from 250V DC control power. Discussion of breaker operation will begin with the ACB breaker open and fully inserted into its switchgear cubicle ("racked in"). With the breaker initially open, the "b" contacts (from the breaker auxiliary switches) are closed. With the closing spring initially discharged, one limit switch contact (LS1) for the closing spring is also closed. The two closed contacts allow current to flow to the charging motor to rotate the cam and charge the closing spring. When the closing spring is fully charged (cam is in ready position), the LS2 contact for the spring release relay closes, and the LS1 contact for the charging motor opens to deenergize the motor. With the closing switch or pushbutton contact C open, the spring release relay remains deenergized and the ACB stays ready for operation. The "b" contact for the green indicating light is shut and the light is illuminated, indicating the breaker is open.

To close the breaker the closing switch is operated, shutting contact C and energizing the spring release relay to remove the spring retention pin. The closing spring rotates the cam to shut the breaker, causing the "b" auxiliary contacts to open and the "a" auxiliary contacts to shut. The green light is deenergized and the red light illuminates. The LS2 contact for the spring release relay opens and the charging motor LS1 contact closes. To open the breaker, the control switch is placed in the trip position causing the "T" contact to shut. This circuit energizes the shunt trip coil, which moves the tripper bar to allow the tripping springs to open

the breaker. The opening action causes "b" contacts to close and "a" contacts to open; the red light is deenergized and the green light illuminates. When the "b" contact closes, the charging motor energizes again to rotate the cam and recharge the closing spring. The breaker is ready for closure again when the closing spring has been recharged (the cam is in the ready position).

Additional auxiliary contacts are provided on many breakers. These contacts can be used for position indication needed in other logic or control systems. Breaker compartment switches are used when racking the breaker out to the test position or for complete removal. In the test position the remote closing feature is defeated to prevent inadvertent actuation while testing. The full out limit switch is used to discharge the closing spring or to recharge it depending on whether the breaker is being racked out or in.

The closing spring can receive its energy manually or from the charging motor. Manually charging the closing spring is accomplished from the front of the breaker with the use of a hand crank and ratchet mechanism. On many breakers the spring retention pin can be manually released to close the breaker by depressing a manual pushbutton on the front of the breaker enclosure. The breaker can also be opened manually using a manual trip button on the front of the breaker enclosure to actuate the tripping bar. The proper breaker operating tools and personnel protection gear should be used when operating breakers locally.

9.5 Protective Relays

System or circuit faults are isolated by opening circuit breakers. In circuit breakers designed to operate below 600 volts, overcurrent fault sensing is often accomplished by direct-acting series trip coils that are built right into the breaker. In breakers above 600 volts, fault sensing is generally accomplished by protective relays that may be mounted within the breaker itself or externally. Protective relays can monitor many different com-

plex circuit conditions: current and voltage magnitudes, phase relations, direction of power flow, and frequency. When an unsafe or intolerable condition is detected, the protective relay actuates contacts to complete the trip-coil circuit in the control circuit of the breaker, to cause the breaker to open to terminate the unsafe condition. In large breakers the trip circuit is usually a DC circuit supplied from a highly protected source, such as the station batteries (vital DC). A pictorial representation of protective relays is shown in Figure 9-18.

A protective relay is an electrical switching device with one or more associated contacts that can be opened or closed to interrupt or complete breaker control circuits. The switching device is normally electromagnetically operated to open or close the contacts through a movable part called the armature. The armature is attracted against spring pressure when the electromagnet is energized, and released by spring pressure when the magnet is deenergized. Protective relays can also be operated by means other than electromagnetic forces. With relay protection, a short circuit, an overload, or any other abnormal condition in the main circuit can be sensed to cause a relay to energize a trip coil control circuit that opens the breaker in the main circuit.

Protective relays are often classified according to the time that will elapse between the occurrence of an abnormal condition and the opening of the circuit. Different durations of delays are used to set up the desired selective tripping protective scheme to protect the remaining distribution circuits. Three general classifications of protective relay types have been established: instantaneous or high-speed, definite time delay, and inverse time delay.

9.5.1 Instantaneous or High-speed

In the instantaneous relay, the time delay is omitted so that the circuit is opened instantly upon the occurrence of an abnormal condition. These relays are used to protect against very high current

short-circuit faults.

9.5.2 Definite Time Delay

The definite time delay relay is designed to have a specific time delay before actuating. The abnormal condition must exist for a set period of time before the relay will cause the circuit breaker to open. The definite time delay relay is used to protect a circuit that is designed for current surges of short duration during equipment startup. The duration is not long enough to damage the circuit in the equipment.

9.5.3 Inverse Time Delay

The inverse time delay relay is also designed to have a time delay in its action. The length of time required to cause the relay to actuate to open the circuit depends on the severity of the abnormal condition. The greater the fault current, the quicker the relay will function.

9.6 Fuses

A fuse (see Figure 9-19) is a current-carrying protective device that destroys itself to break (open) a circuit before the associated wiring and equipment are damaged. Most fuses cannot be reused.

The basic fuse consists of a strip of metal, generally zinc or an alloy of tin and lead, that will melt at a lower temperature than the wire in the circuit. The fuse is placed in series with the circuit. The fuse has a higher resistance than that of the circuit wiring, causing it to heat faster than the conductor. It should melt before damage occurs to the circuit wiring or equipment.

Fuses are rated by the number of amperes of current that will flow through them without melting the element. For example, a 20-amp fuse will permit 20 amperes of current to flow through it. If the current rises a little above 20 amps, the fuse will carry the overload for a short time without blowing (melting). However, if a large overload occurs, the fuse melts quickly before the circuit

wires become hot. The most common types of fuses used in the power plant are discussed below.

9.6.1 Low-Voltage Cartridge Fuse

In the cartridge fuse, the metal strip (element) is enclosed in a fiber tube. Metal caps at the ends of the tube are connected to the fuse element. Usually the tube is filled with a protective powder that helps to break the circuit quickly, preventing current from flowing in an arc between the unmelted portions of the fuse metal. When the one-time cartridge fuse has melted, it must be replaced with another fuse of the same rating. The cartridge fuse has ferrule or knife-blade type contacts.

9.6.2 High-Voltage Fuses

High-voltage fuses are used in circuits having more than 600 volts. This type of fuse is designed for safe interruption of current with high voltages. One example of a high-voltage fuse is the boric acid expulsion fuse shown in Figure 9-19. It consists of a glass tube lined with boric acid that acts as an extinguisher for the electric arc that would be created when the fusible bar or wire begins to open.

9.7 Special Onsite Distribution Equipment

Most nuclear plant electrical distribution systems include special equipment designed to improve the reliability and continuity of power to selected plant components. Automatic bus transfer devices use two AC power sources to maintain power continuity, while inverters use DC power, normally from a battery. Uninterruptible power supplies use both AC and DC power to accomplish the power continuity objective.

9.7.1 Automatic Bus Transfer Devices

One method of providing continuity of power to selected plant components is through the use of automatic bus transfer (ABT) devices. An ABT device is a device which senses normal bus voltage, and automatically transfers the load from the

normal bus to a backup bus when voltage is lost on the normal bus. With two sources of power available, one supplying power to the equipment and the other in standby, a loss of the active power source is sensed by the ABT device and the component is automatically disconnected from the deenergized bus and connected to the standby bus. Depending on the design of the ABT device, the transfer may be performed fast enough to prevent the affected equipment from tripping on undervoltage.

9.7.2 Inverters and Battery Chargers

An inverter is a device that converts DC power to AC power. A battery charger converts AC power to DC power. Both of these devices are normally solid-state components in modern nuclear plants. The relationship of an inverter and battery is shown in Figure 9-8. Normally, the battery charger is supplying all DC bus loads, while maintaining the battery fully charged. If the battery charger suffers a failure or loses power, the electron flow into the battery instantaneously reverses direction, and the battery supplies the 125V DC bus loads. The source of the electron flow (battery charger or battery) makes no difference to the inverter, which continues to use DC power from the DC bus to generate AC power. Of course, the battery charger must be returned to operation before the battery is exhausted.

9.7.3 Motor-Generator Sets

As indicated in section 9.7.2, modern inverters and battery chargers are normally solid-state components. Some older plants may use motor-generator sets to accomplish the same functions as battery chargers and inverters. An AC motor can be used to drive a DC generator to charge a battery with DC power, or a DC motor can be powered from a battery and be used to drive an AC generator to provide special-purpose, reliable AC power. In modern plants, motor-generator sets are sometimes used for these purposes if the load power requirements are greater than a solid-state charger or inverter can provide.

9.7.4 Uninterruptible Power Supplies

Figure 9-20 illustrates the basic components of an uninterruptible power supply (UPS) (see Table 9-1). An UPS uses a battery charger, a battery, an inverter, a regulated AC transformer, and a static or manual transfer switch to supply continuous power to essential, low-power loads such as safety instrumentation. In an UPS these components are normally combined in one solid-state device.

The relationship of the battery charger, battery, and inverter in an UPS was described in section 9.7.2 for Figure 9-8: if voltage is lost from the normal AC source, the battery will instantaneously reverse its current flow direction and send power to the inverter to produce AC power. As shown in Figure 9-20 for a UPS, the addition of the regulated transformer and the transfer or bypass switch allows the inverter to be bypassed if it develops a fault or needs maintenance. The bypass switch may be a static transfer switch (automatic device) to maintain an uninterrupted AC power output from the UPS, or it may be set up for manual operation only.

9.8 Batteries

The batteries used for supplying DC voltage and current are made up of voltaic cells. The cells used in station batteries are rechargeable and provide power by electrochemical means. Although differing widely in construction, all battery cells have an electrolyte, anode, and cathode, as well as a nonconducting container.

Chemical action, encouraged by the electrolyte, takes place at the anode and the cathode, and produces an electrical potential at the respective terminals. Completing an external circuit between the anode and cathode will allow current to flow. One of the more commonly used batteries is composed of cells with a lead peroxide cathode, a sponge lead anode, and a sulfuric acid electrolyte. Porous sponge lead rather than lead plate is used for the anode to provide increased surface area for

the electrolyte to contact and the chemical action to occur.

Cells may be externally connected in a variety of ways to yield a number of terminal voltages and amperages. Series connections of the cells raise the voltage in increments while parallel cell connections increase the current available. A combination of these wirings is generally used to achieve a convenient voltage and high capacity. Battery capacity is measured in ampere-hours and is based upon the battery delivering X number of amps for Y number of hours.

9.8.1 Cells and Batteries

To discuss cells and batteries, we must first define these terms. An electrochemical cell refers to a single unit that converts chemical energy into electrical energy. A battery is a combination of two or more cells.

Batteries may be much smaller than other energy sources such as mechanical generators or transformer power supplies in radio and television receivers. They do not have the noisy moving parts like mechanical generators. Batteries do not develop any appreciable electrical noise such as the static caused by sparking of the brushes in a generator. Batteries need only a small amount of maintenance and are usually dependable. However, batteries are limited in size for a specific current rating and are sensitive to temperature variations.

9.8.2 Construction of a Lead-Acid Storage Battery

The lead-acid battery is an electrochemical device for storing chemical energy until it is released as electrical energy. Active materials within the battery react chemically to produce a flow of direct current whenever current consuming devices are connected to the terminal posts on the electrodes. This current is produced by chemical reaction between the active material of the plates (electrodes) and the electrolyte (sulfuric acid).

The parts of a lead-acid battery are illustrated in Figure 9-21 and are discussed in the following paragraphs.

A lead-acid battery consists of a number of cells connected together; the number needed depends upon the voltage desired, with each cell producing approximately 2.1 volts.

A cell consists of a hard rubber, plastic or bituminous material compartment into which is placed the cell element, consisting of two types of lead plates, known as positive and negative plates. These plates are insulated from each other by suitable separators (usually made of plastic, rubber, or glass) and submerged in a sulfuric acid solution electrolyte.

The plates are formed by applying lead oxide paste (PbO) to a grid made of a conductive alloy. The plates are put through separate electrochemical processes that convert the PbO of the positive plates into lead peroxide (PbO₂) and the PbO of the negative plates into spongy elemental lead (Pb), which is honeycombed and porous.

The positive plates (lead peroxide) and the negative plates (spongy lead) are referred to as the active material of the battery. However, these materials alone in a container will cause no chemical action unless there is a path for interaction between them. The electrolyte provides this path for interaction and carries the electric current within the battery.

A battery container is the receptacle for the cells that make up the battery. Most containers are made from hard rubber, plastic or bituminous composition that is resistant to acid and mechanical shock, and is able to withstand extreme weather conditions. Most batteries are assembled in a one-piece container with compartments for each individual cell.

Cell connectors are used to connect the cells of a battery in series. The element in each cell is placed so that the negative terminal of one cell is

physically located adjacent to the positive terminal of the next cell; they are connected both physically and electrically by a cell connector. Connectors must be of sufficient size to carry the current demands of the battery without overheating.

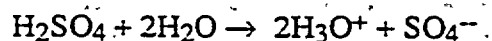
The cells have vent openings with covers made of permeable material to permit the slow escape of hydrogen gas that may form within the cells, while preventing leakage of the electrolyte. These openings are also used to determine the level and chemical state of the electrolyte.

9.8.3 Storage Battery Operation

In its charged condition, the electrodes in the lead-acid battery are lead peroxide (used as the positive plate) and sponge lead (used as the negative plate). The electrolyte is a mixture of sulfuric acid and water. The strength (acidity) of the electrolyte is measured in terms of its specific gravity. Specific gravity is the ratio of the weight of a given volume of electrolyte to the weight of an equal volume of pure water. Concentrated sulfuric acid has a specific gravity of about 1.830; pure water has a specific gravity of 1.000. The acid and water are mixed in a proportion to give the desired initial specific gravity. For example, an electrolyte with a specific gravity of 1.210 requires roughly one part of concentrated acid to four parts of water.

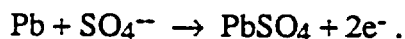
In a fully charged ideal battery, the positive plates are pure lead peroxide and the negative plates are pure lead. Also, all acid is in the electrolyte so that the specific gravity of the electrolyte is at its maximum value. The active materials of both the positive and negative plates are porous, and have absorption qualities similar to a sponge. The pores are filled with the battery solution (electrolyte) in which they are immersed.

When sulfuric acid (H₂SO₄) is diluted in water, the following ionic dissociation occurs:

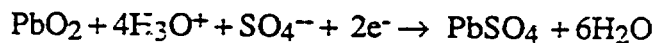


The basic chemical reaction occurring at the

negative plates when the cell discharges (produces current) is the loss of electrons by the lead (oxidation) and the formation of lead sulfate, PbSO_4 .



At the positive plates, lead peroxide gains electrons (is reduced) and passes into solution as Pb^{++} ions (reduction). The Pb^{++} ions combine with SO_4^{--} ions, again forming lead sulfate, PbSO_4 :



These equations show that an excess of electrons is produced at the negative plates and that electrons are consumed at the positive plates. Thus, a flow of electrons (current) occurs during discharge when an external conduction path is provided between the negative and positive plates. The equations also show that as the cell discharges, a coating of insoluble lead sulfate (PbSO_4) builds up on *both* the positive and negative plates. The PbSO_4 causes an expansion of the materials and a gradual clogging of the voids or pores of the plates. If the discharge is prolonged excessively, expansion may take place resulting in uneven swelling of the spongy lead, which creates mechanical stresses that may reduce the battery life.

During the discharge process, the conversion of the electrolyte ions to lead sulfate and water causes the acid concentration of the electrolyte to decrease, which decreases the specific gravity of the electrolyte. When so much of the active material has been converted into lead sulfate that the cell can no longer produce sufficient current, the cell is considered discharged.

If the charged cell is then connected to a DC charging source with a voltage slightly higher than the cell voltage, electrons will flow into the cell in the opposite direction from that occurring during discharge, and a charging process will occur. The cell will use the electrons to convert the lead sulfate and water back into the initial active constituents. During charging operations, lead sulfate is converted to lead at the negative plates and lead

sulfate is converted to lead peroxide at the positive plates, resulting in a gain of porosity ("sponginess") in the plates. At the same time, the sulfate ions are restored to the electrolyte with the result that the specific gravity of the electrolyte increases. The chemical reactions occurring during the charging process are as follows:

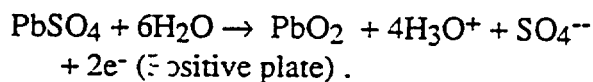
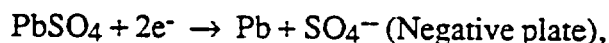
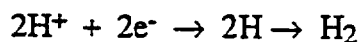


Figure 9-22 illustrates the chemical actions that occur during discharge and charging operations.

One of the dangers involved in using lead-acid storage batteries is the production of hydrogen gas. Hydrogen ions are always present in the sulfuric acid electrolyte. The hydrogen ions are readily available to react with free electrons at the cathode during battery discharge operations, or at the anode during battery charging operations, to produce free hydrogen, which immediately coalesces to form hydrogen gas by the following reaction:



The slow production of hydrogen gas during normal battery operations can be dissipated through the porous vent caps on the cell tops. The use of excessive charging voltage during battery charging operations could cause rapid hydrogen production and lead to the possibility of a hydrogen explosion.

An inspection of the reactions that occur during the battery discharge operations shows that the SO_4^{--} ion and the H_3O^+ ion are "consumed" in producing the lead sulfate coating and water that result from these reactions. The SO_4^{--} ion and the H_3O^+ ion are the constituents of the sulfuric acid. Therefore, the sulfuric acid is being continuously consumed during the discharge operations to produce the discharge current flow. The discharge

reaction equations show that the greater the discharge current flow rate is, the faster the sulfuric acid is consumed.

An inspection of the reactions that occur during charging operations shows that lead sulfate and water are converted back to H_3O^+ and SO_4^{--} ions. Therefore, the sulfuric acid is continuously regenerated during the charging operations. Similar to the discharge operations, the greater the charging flow rate is, the faster the sulfuric acid is regenerated.

The total amount of sulfuric acid consumed at any time during discharge operations is directly proportional to the total amount of current discharged. Therefore, the specific gravity of the electrolyte can be used to determine the state of discharge of the lead-acid cell. A similar relationship holds during charging operations. Therefore, the specific gravity of the electrolyte in battery cells is routinely measured to determine the state of discharge (or charge) of the battery.

In summary, the chemical reactions in a lead-acid storage battery during charging and discharging may be conveniently summarized by a combined, reversible chemical equation:

Discharging -->



<-- Charging

During discharge the combined reaction proceeds from left to right as both the positive plates (lead peroxide) and the negative plates (sponge lead) react with the sulfuric acid to *produce current flow*. During discharge *both* plates become coated with lead sulfate (PbSO_4) and the electrolyte (H_2SO_4) is diluted by the formation of water. During charging operations the combined reaction proceeds from right to left as electrical current *from an outside source* is used to convert the lead sulfate and water back into the original constituents: lead peroxide on the positive plates, sponge

lead on the negative plates, and sulfuric acid in the electrolyte.

9.8.4 Hydrometer

The specific gravity of a cell can be determined by use of a hydrometer, which consists of a float within a syringe. The hydrometer float is a hollow glass tube weighted at one end and sealed at both ends. A scale calibrated in specific gravity is laid off axially along the body (stem) of the tube. When the electrolyte to be tested is drawn up into the syringe, the hydrometer float will sink to a certain level in the electrolyte. The distance that the hydrometer stem protrudes above the level of the liquid depends upon the specific gravity of the solution. The reading on the stem at the surface of the liquid is the specific gravity of the electrolyte in the syringe.

9.8.5 Potential Difference and Current

The potential difference or voltage of a cell is determined by the ease with which the electrodes yield positive or negative ions. The potential difference is determined by the types of materials used in the cell. The size of the cell or any of its parts does not affect the potential difference the cell is capable of producing. As an example, the materials used in the lead acid cell will always produce a potential difference of 2.1 volts per cell when fully charged. If we change the material of one of the electrodes in a cell, we will change the potential difference of the cell.

On the other hand, the amount of current produced by a cell is determined by the size of the electrodes (assuming the concentration (specific gravity) and quantity of the electrolyte is adequate). The greater the volume of the active material in the electrodes, the greater the current capacity of the cell is.

9.8.6 Cell Capacity

The capacity of a storage cell, expressed in ampere hours, is the product of the discharge

current in amperes multiplied by the number of hours the cell will maintain that current. It is understood that the cell must be fully charged at the start of the discharge, when determining its capacity. The ampere hours that may be obtained from a battery are greater for a long, low rate or intermittent rate of discharge, than for a short, high rate of discharge. This is because the voltage drops faster at the higher rate.

All batteries are given a capacity rating, which is the ampere hours obtainable under certain working conditions. Suppose a typical battery used as a backup source of power for the AC instrument bus inverters is rated at 800 ampere hours at an 8 hour rate. This means that over an 8 hour period, the battery is capable of supplying 800 amperes, or 100 amperes per hour. A greater capacity can be obtained if the discharge rates are made lower; conversely, the capacity is reduced as the discharge rate increases. This characteristic is the reason that battery loads must be minimized during a "blackout" or loss of all AC power (including failure of standby power sources).

The capacity of a cell is also affected by the temperature at which it is operated. Usually, the capacity decreases when a cell is operated at low temperatures. In fact, at about -30°C , most electrochemical cells stop supplying energy because the electrolyte freezes.

9.8.7 Battery Charges

When a new battery is shipped dry, the plates are in an uncharged condition. After the electrolyte has been added, the plates must be converted into the charged condition. This is accomplished by giving the battery a long low-rate initial charge that is referred to as a freshening charge.

A normal or regular charge is given to the battery on a periodic basis, or if necessary to restore the energy taken out on a discharge. This regular charge should be given at the normal rate specified by the manufacturer. If it is necessary to hasten the charge, a higher rate may be used,

provided it is reduced from time to time to prevent excessive hydrogen production.

An equalizing charge is an extended normal charge. This type of charge is performed periodically to ensure that all the sulfate is driven from the plates and that all the cells are restored to a maximum specific gravity.

The practice of keeping a battery connected to a bus in readiness to take unexpected, emergency or high momentary loads is well established. Such batteries are continually maintained in a fully or almost fully charged condition by receiving a continuous charge at an extremely low rate, just enough to counteract the small internal losses that are present in every storage battery. Periodic regular charges are given to the battery at slightly higher voltages to break up any stagnation in the electrolyte.

9.9 Emergency Responses

Although the electrical distribution system is also needed for normal operations, the critical design functions for the system involve the provision of reliable power to the safety-related equipment during emergencies.

9.9.1 Plant Trip

For a plant trip, the main generator will be promptly tripped off the line, and the main generator breaker(s) to the grid will be tripped open. If the main generator was supplying onsite loads through an auxiliary transformer, the opening of the generator breakers may initiate an automatic fast transfer such that the reserve supply breakers will close to provide power to the plant directly from the grid. The fast transfer will include the emergency or vital buses if they were not already being powered directly from the grid. In many plants, the transformers for plant loads are located on a branch off the line from the switchyard to the main generator as shown for the NSSTs in Figure 9-7. At these plants there is normally no need for a fast transfer on a plant trip; power is instant-

neously backed from the grid through the main transformers to the normal service station transformers so there is no loss of normal power. For either arrangement, the emergency diesel generators remain shut down on a normal plant trip, and there is no significant perturbation on the vital (safety-related) buses.

9.9.2 Loss of Offsite Power

For a loss of offsite power, the plant will trip, and the emergency diesel generators will be automatically started when the loss of voltage on the vital buses is sensed. Each diesel generator breaker will close automatically when the associated diesel generator attains rated speed and voltage. If all the emergency pump motors were still connected to the vital buses, they would all try to start the instant the breaker closed. The combined starting currents of all the emergency motors would put a serious overload on the diesel generator, causing a diesel trip and/or other possible damage. This unsatisfactory situation is prevented by using load shedding (see Table 9-1), which is the automatic disconnection of all the major loads on the vital buses when the loss of vital bus voltage is initially sensed.

Note that if the normal supply for the emergency buses is from the nonvital buses as shown in Figure 9-8, the load shedding function will also include disconnecting all the nonvital connections from the vital buses. Also note that some loads will remain continuously connected to the vital buses, but these will be small, essential loads such as instrumentation and communications.

Load sequencing (see Table 9-1) is the term applied to the staggered time sequence that is used for reloading the major emergency loads back onto the vital buses after the diesel generator breaker has closed. The loads are sequenced to start in a predetermined order with a spacing of 5 to 10 seconds. The time spacing allows the large motor starting currents to subside before each additional motor is started. If diesel loading allows, some nonvital loads may be subsequently

manually restarted by the operators.

9.9.3 Safety Injection Actuation

For a safety injection (Emergency Core Cooling system) actuation, the plant is tripped, and the emergency diesel generators are automatically started as a precautionary measure. Normally, the electrical power supply response is essentially identical to that for a plant trip, except that the diesel generators are running unloaded.

If offsite power is subsequently lost during a safety injection actuation, load shedding is again actuated, causing all the major loads (and any non-vital bus ties) connected to the vital buses to be automatically disconnected. Because the diesel generators are already running, the output breakers will close almost immediately and load sequencing will begin.

The order in which the emergency loads are sequenced onto the vital buses on a loss of offsite power after a safety injection actuation signal normally differs from the simple loss of offsite power situation. Loads used for a loss of coolant accident need priority during a safety injection, but not during a simple loss of offsite power situation.

Table 9-1. Definitions

<u>REDUNDANCY</u>	-	A system or component that duplicates the essential functions of another system or component to the extent that either one can perform the necessary function regardless of the operational condition of the other.
<u>TRAIN SEPARATION</u>	-	The physical and electrical separation of redundant electrical trains, structures, and components to prevent a fault in one electrical train from affecting the operation of the redundant train.
<u>LOAD SHEDDING</u>	-	The process of disconnecting all nonvital connections and deliberately removing most (preselected) large loads from a vital bus in response to an undervoltage condition on the vital bus.
<u>LOAD SEQUENCING</u>	-	The process of starting large emergency motor loads in a preselected order (rather than all at once) on a vital bus after load shedding has occurred on that bus. Load sequencing assures that essential equipment is energized as quickly as possible while overcurrent conditions (i.e., overloading the emergency diesel generator) due to starting a large number of motors at the same time are avoided.
<u>SELECTIVE TRIPPING</u>	-	The process of electrical fault isolation using protective devices in series with one another such that the protective device nearest to the fault operates first to protect the integrity of the overall system. A properly designed protective scheme will isolate a fault by removing the least number of components from service.
<u>UNINTERRUPTIBLE POWER SUPPLY</u>	-	A solid state device that uses a battery charger, battery, and inverter to provide a continuous supply of regulated AC power for essential, low power loads such as process controllers, emergency instrumentation, plant computers, control power, emergency lighting, and communications.
<u>CLASS 1E ELECTRICAL COMPONENTS</u>	-	The safety classification term given to safety-related electrical equipment that is used in systems that are essential to emergency reactor shutdown, containment isolation, and reactor core cooling, or are otherwise essential in preventing a significant release of radioactive material to the environment.

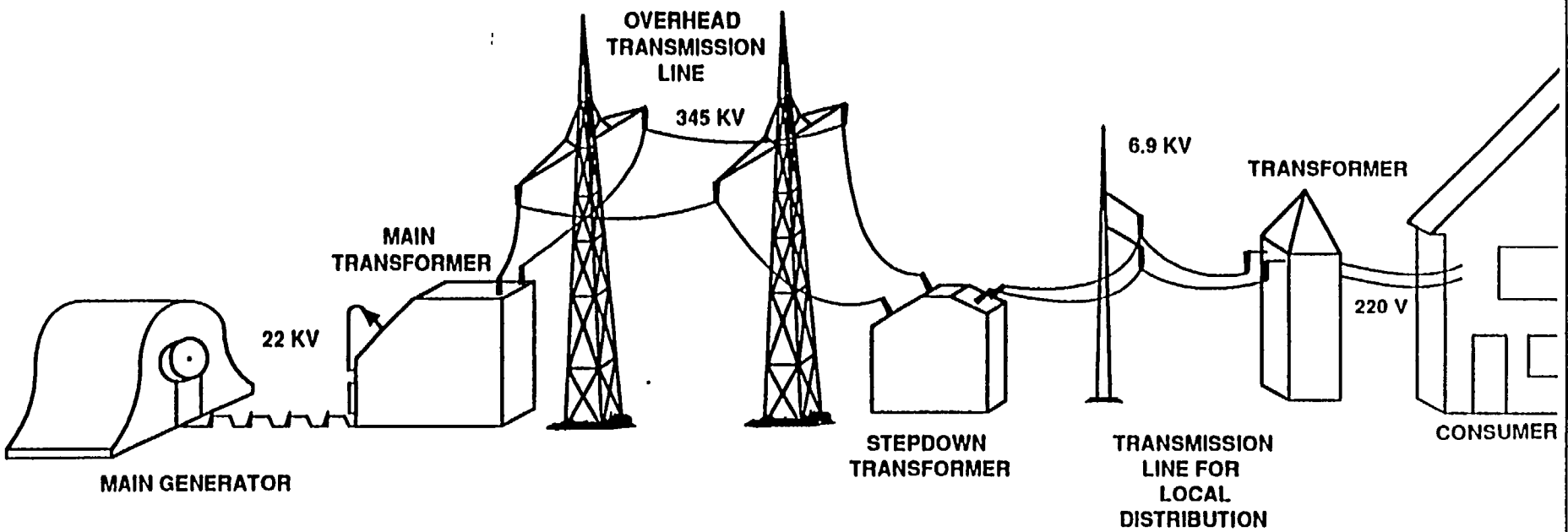


Figure 9-1. Simplified Grid System

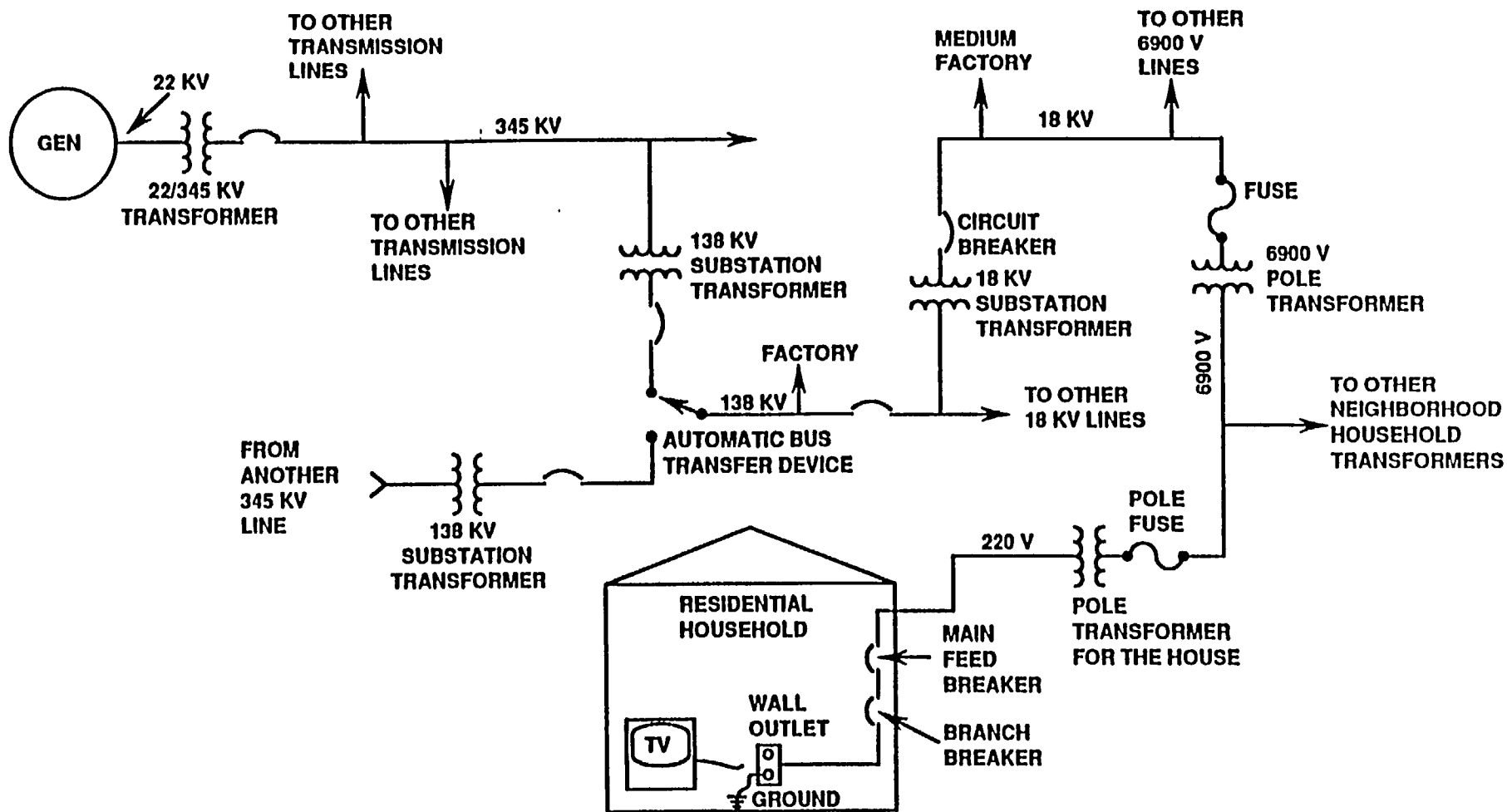


Figure 9 - 2. Typical Distribution System

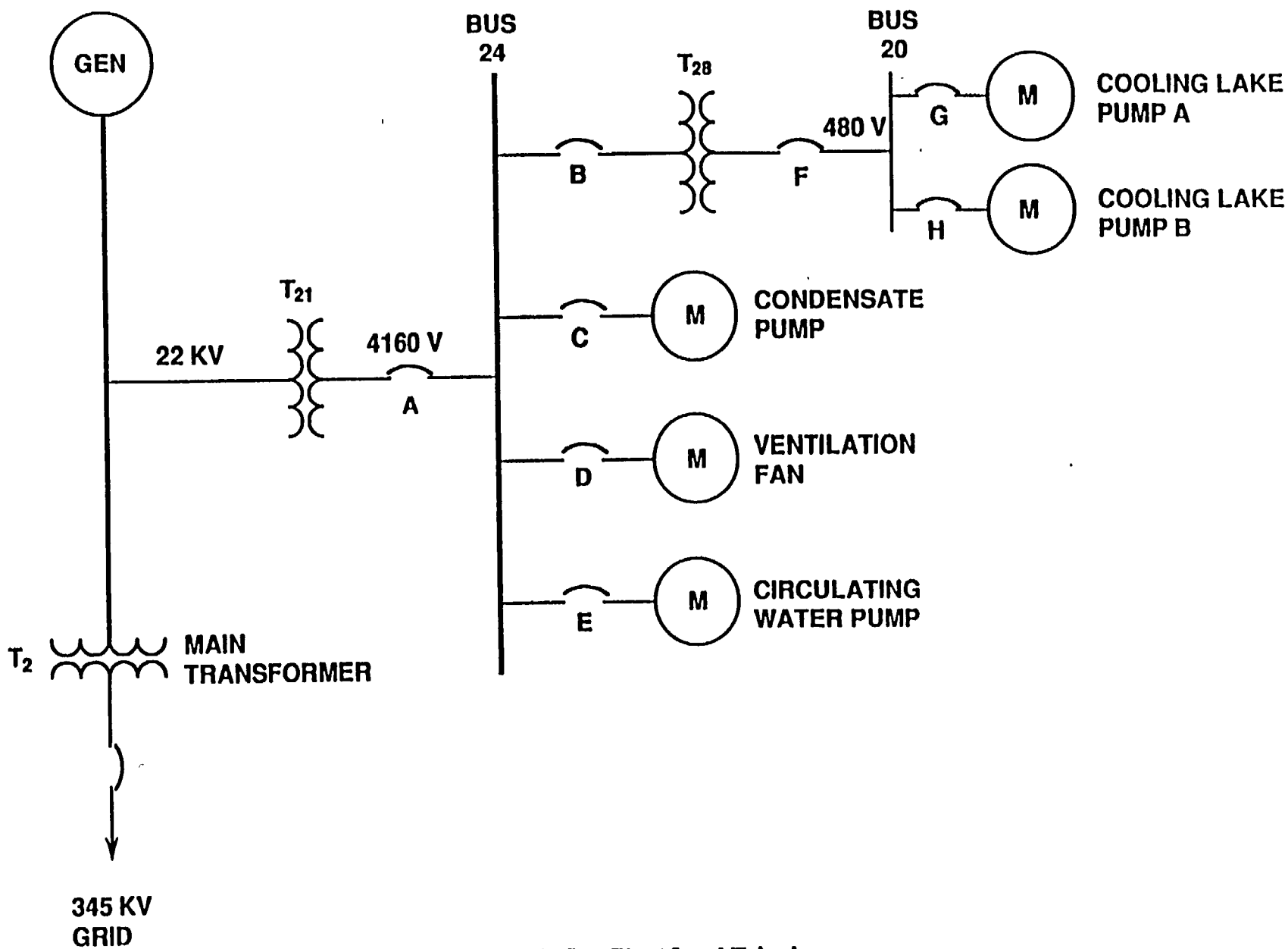


Figure 9 - 3. In - Plant Load Tripping

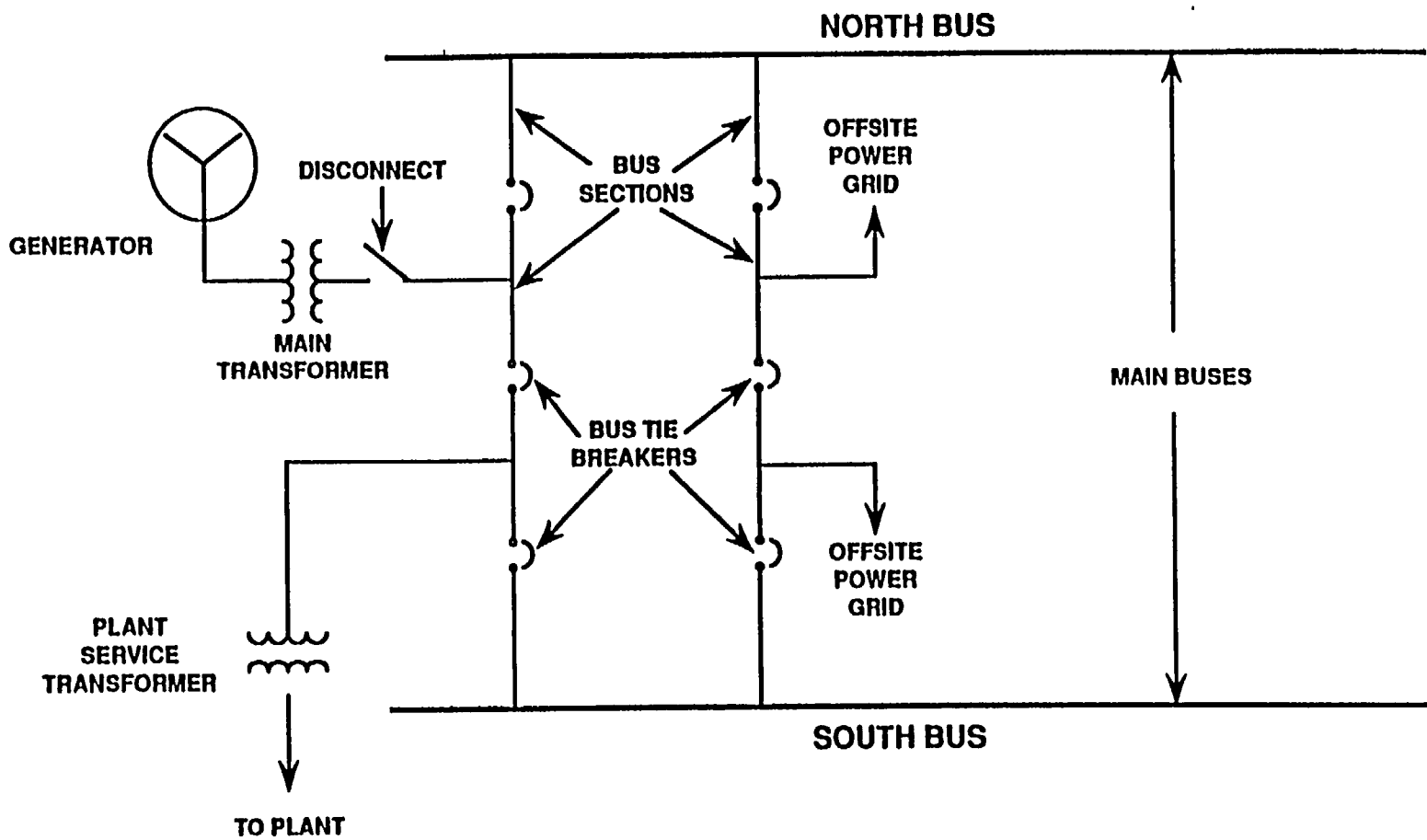


Figure 9 - 4. Switchyard Bus Arrangement

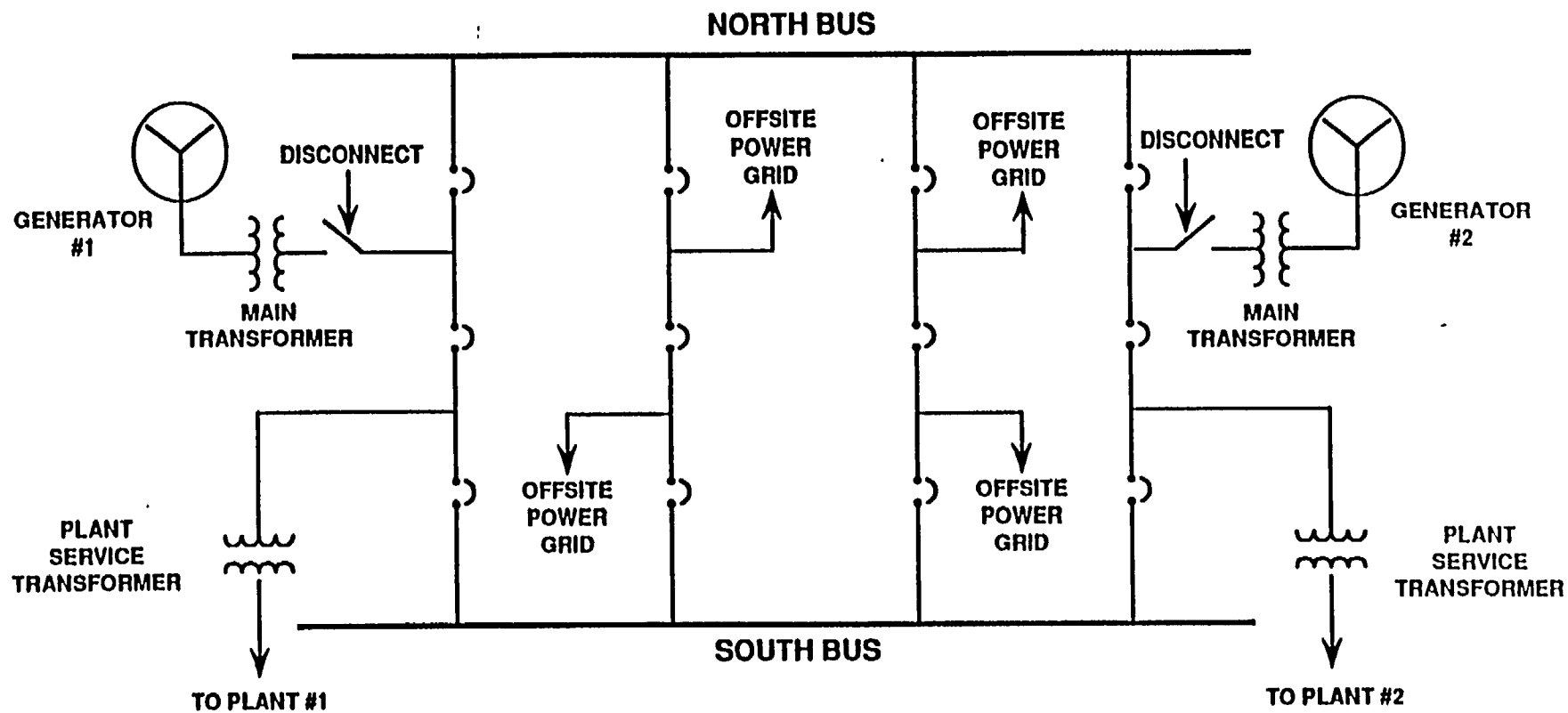


Figure 9 - 5. Parallel Bus Arrangement

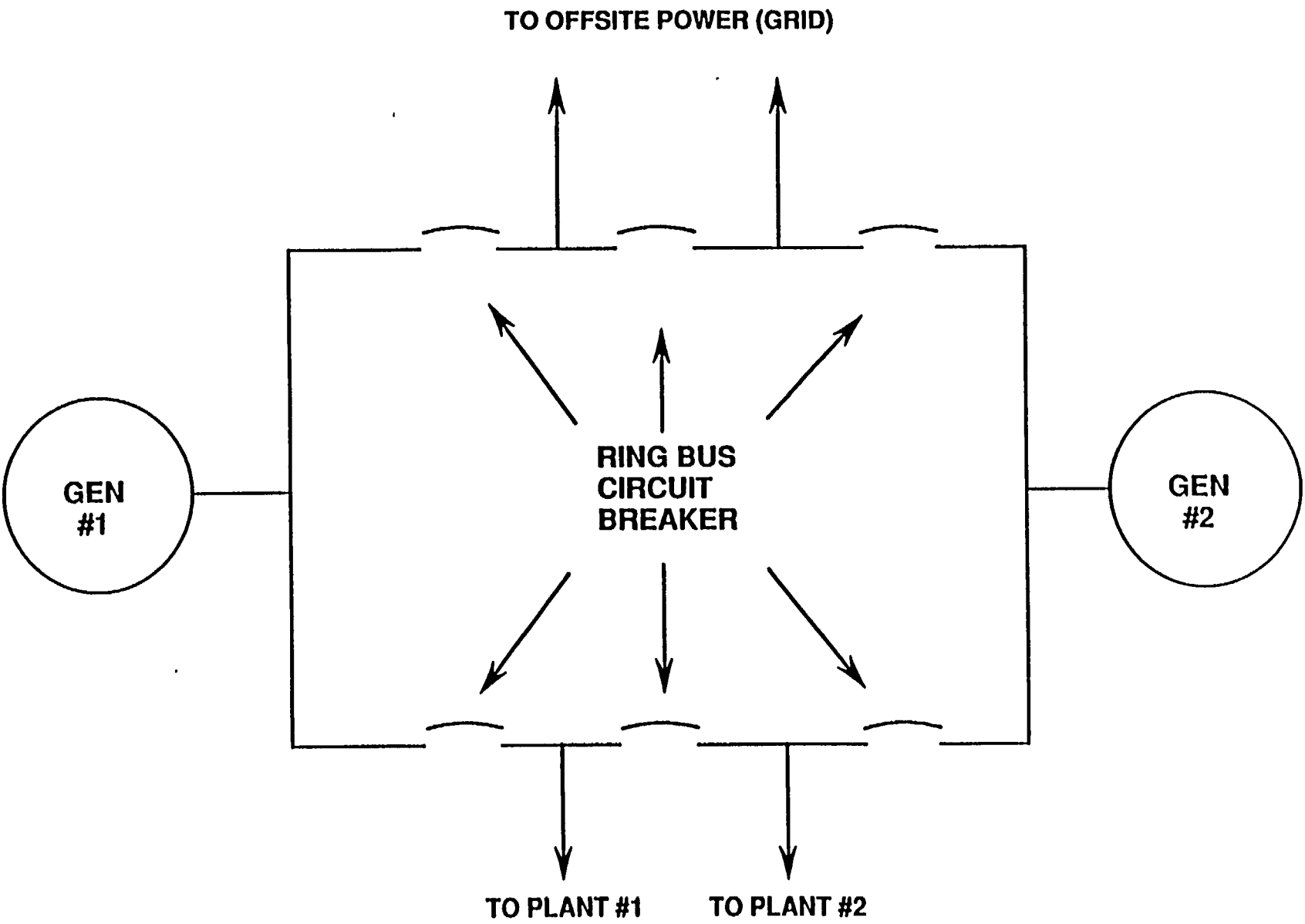


Figure 9-6. Ring Bus Arrangement

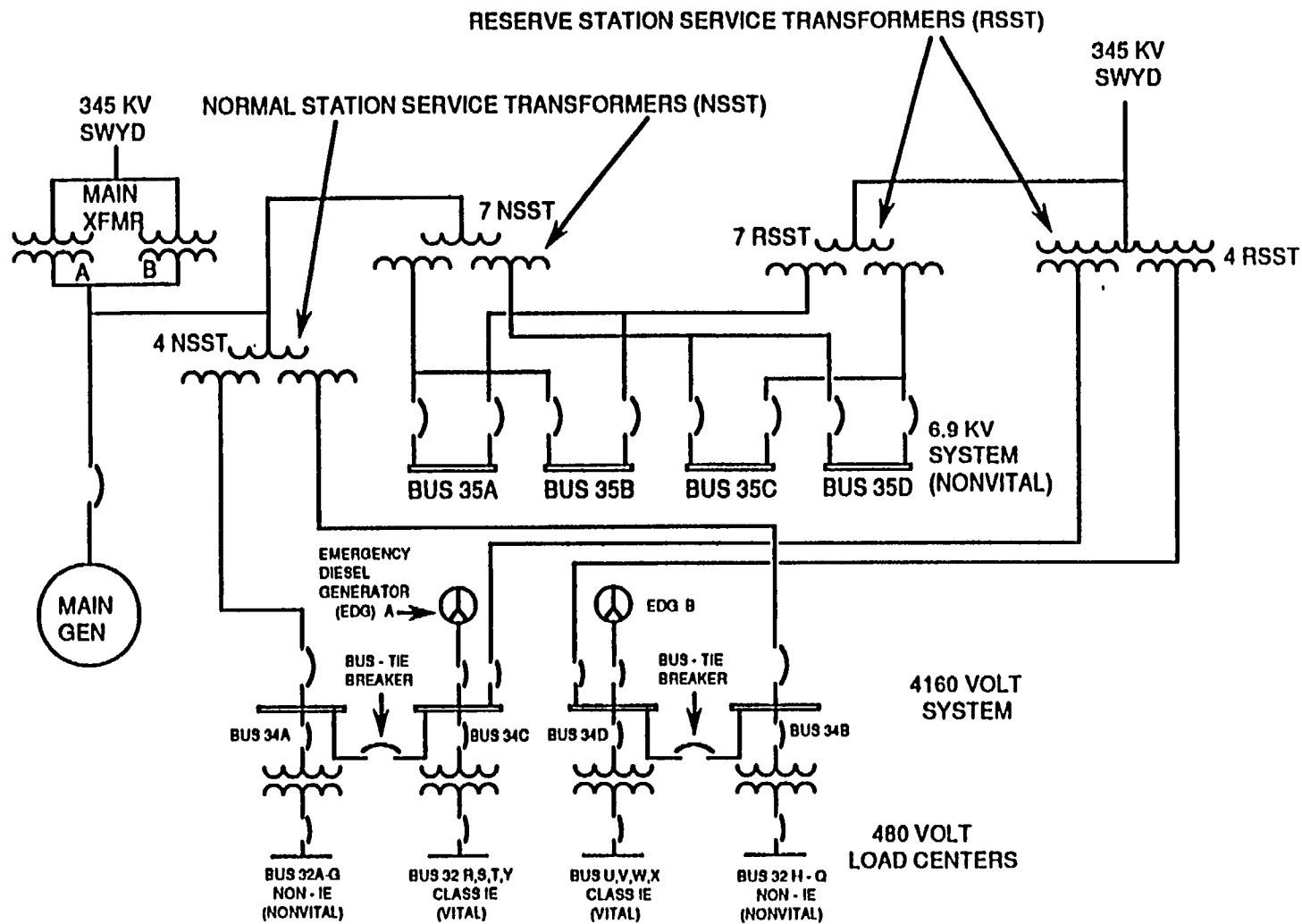


Figure 9 - 7. Typical Onsite Distribution System

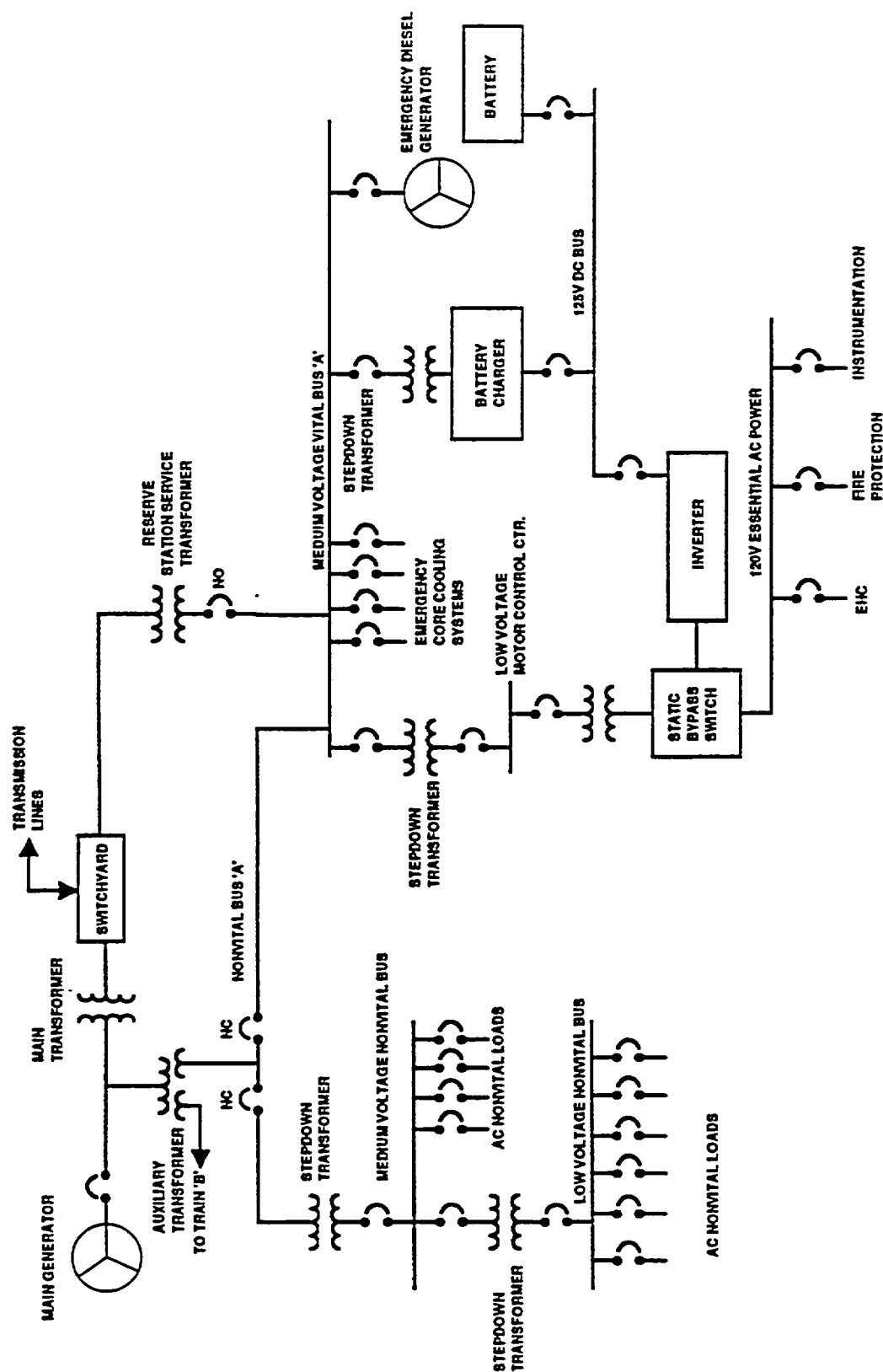


Figure 9 - 8. Vital and Nonvital Subsystems

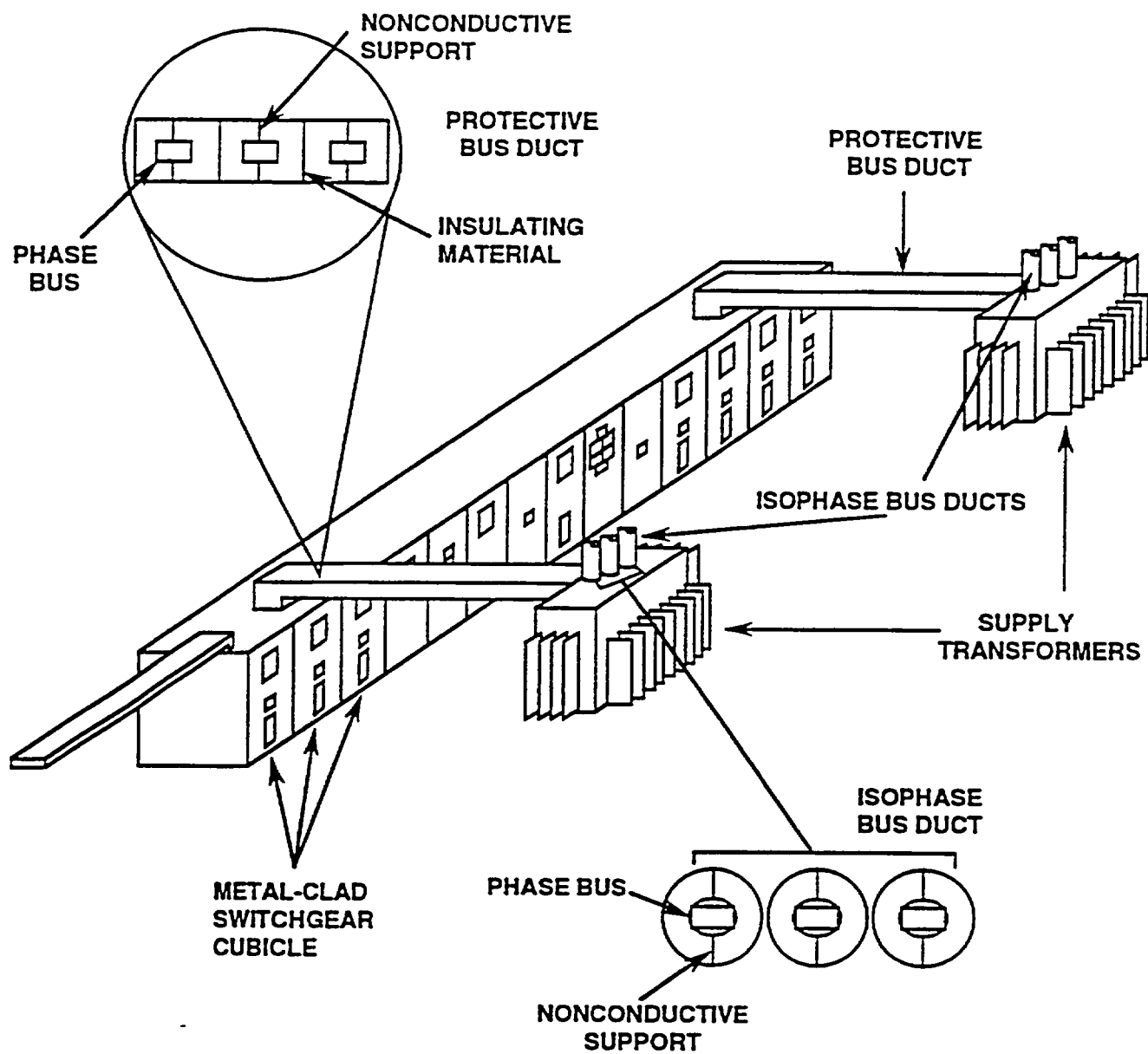


Figure 9 - 9. In - Plant Protective Bus Ducts

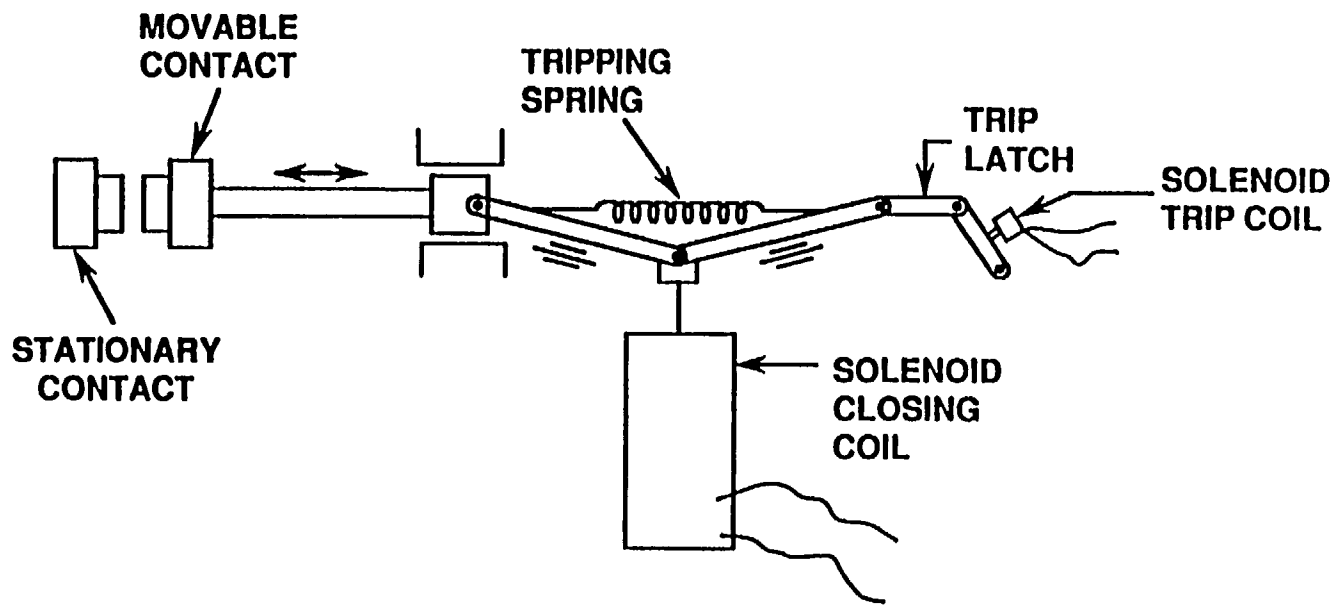


Figure 9 - 10. Solenoid - Operated Circuit Breaker Operating Mechanism

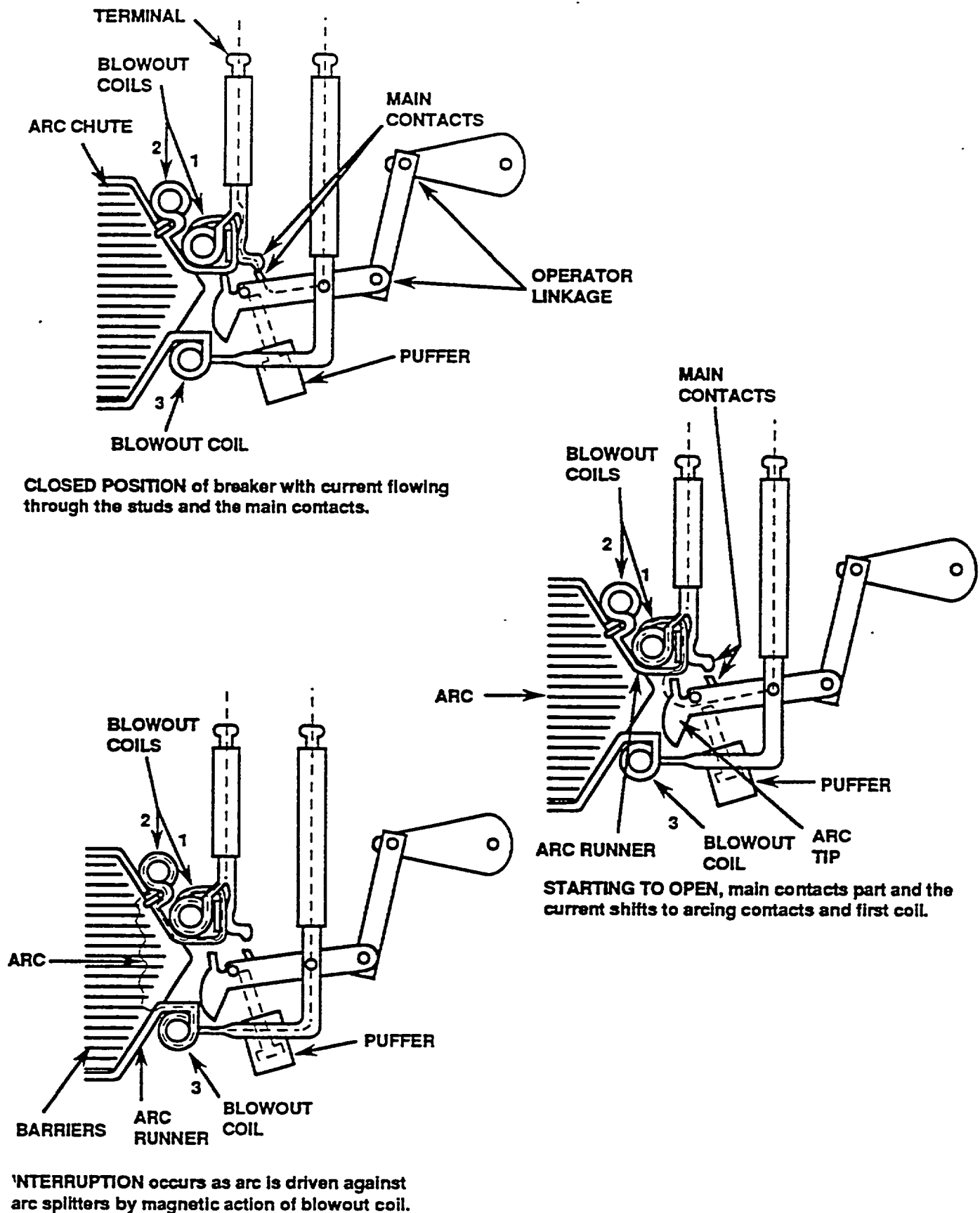


Figure 9-11. Air-Circuit Breaker Operation

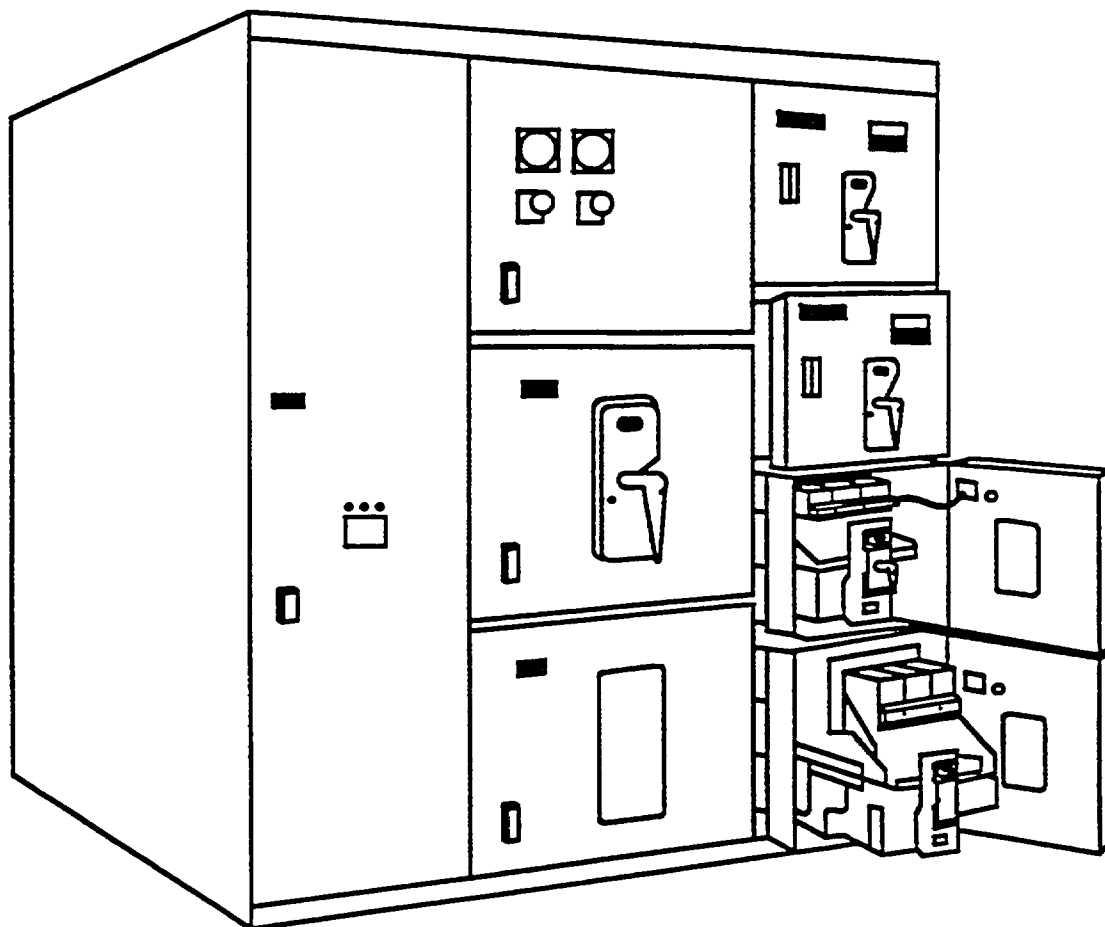
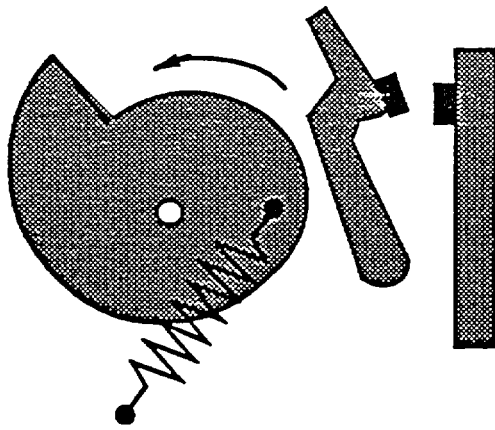
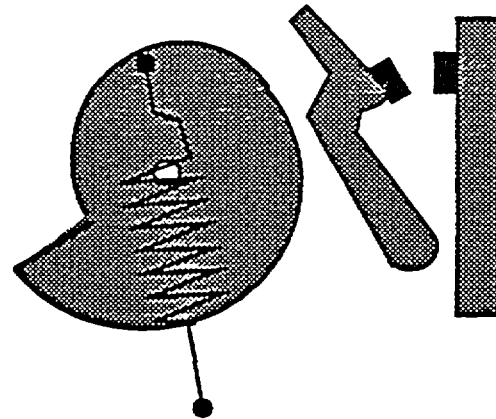


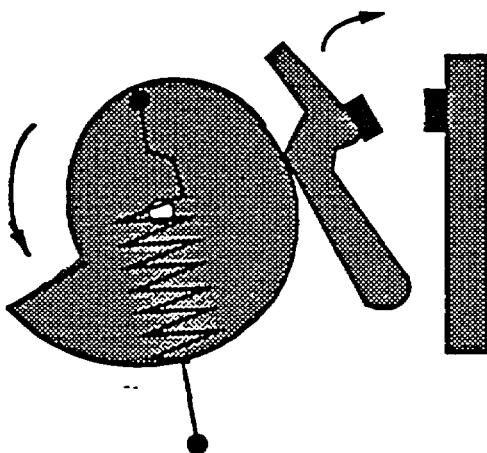
Figure 9 - 12. Load Center With Air Circuit Breakers



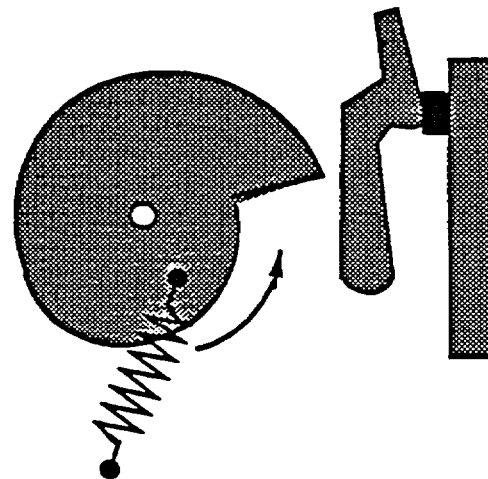
A. ENERGY IS STORED BY ROTATING CAM WITH CHARGING MOTOR OR LEVER-OPERATED RATCHET MECHANISM, EXPANDING (CHARGING) POWERFUL CLOSING SPRING.



B. ENERGY IS POISED AT CROSSOVER POINT. SPRING RETENTION PIN KEEPS CAM POISED AT READY POSITION UNTIL BREAKER OPERATION IS REQUIRED.



C. ENERGY IS RELEASED AND SPRING ROTATES THE CAM RAPIDLY, SHOVING THE MOVEABLE CONTACT TOWARD THE STATIONARY CONTACT.



D. THE CONTACTS ARE CLOSED AS THE CAM COMPLETES ITS TRAVEL, AND ARE HELD CLOSED BY THE TRIPPER BAR (NOT SHOWN).

Figure 9-13. Cam-Operated Breaker Sequence

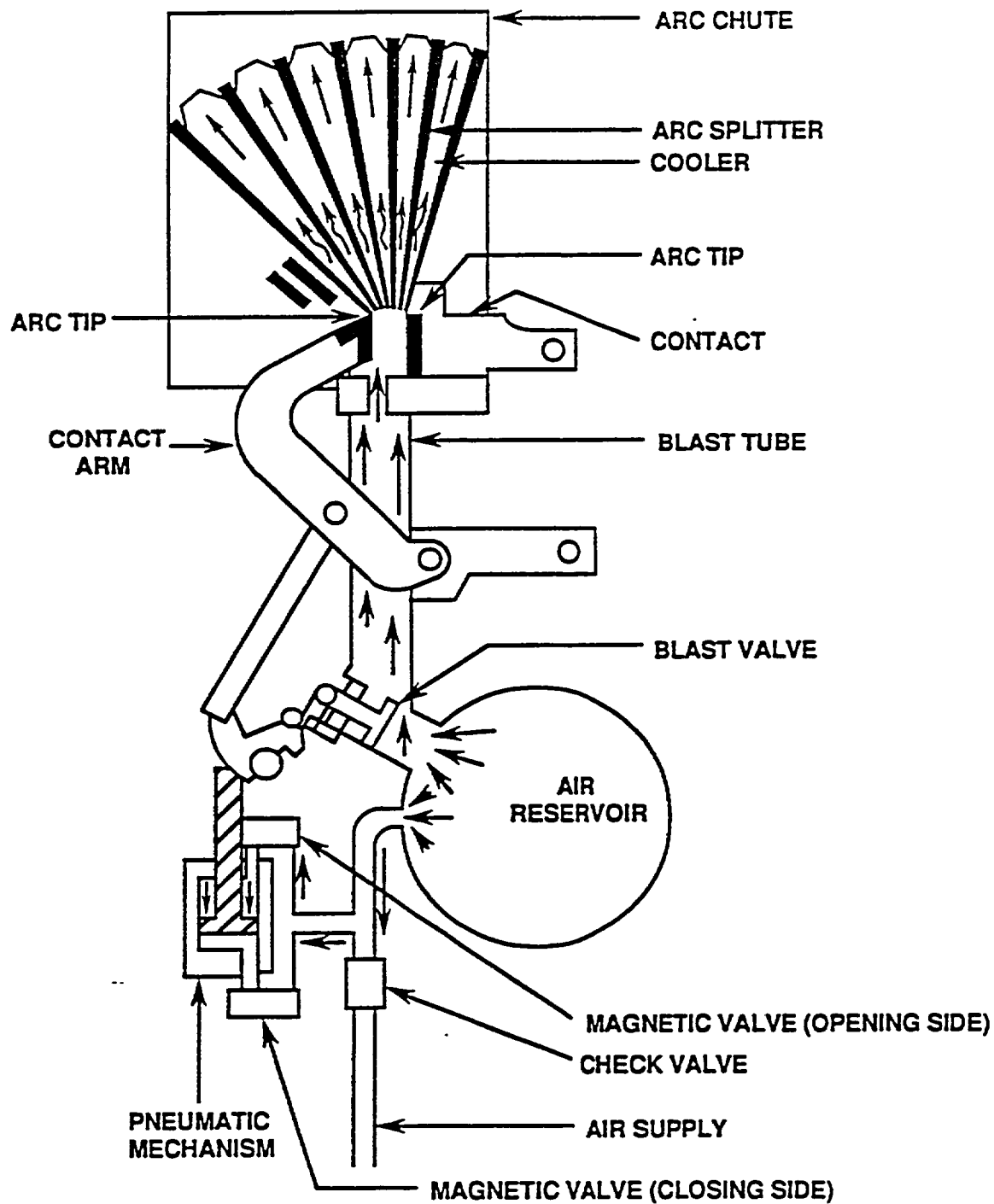


Figure 9-14. Air-Blast Circuit Breaker

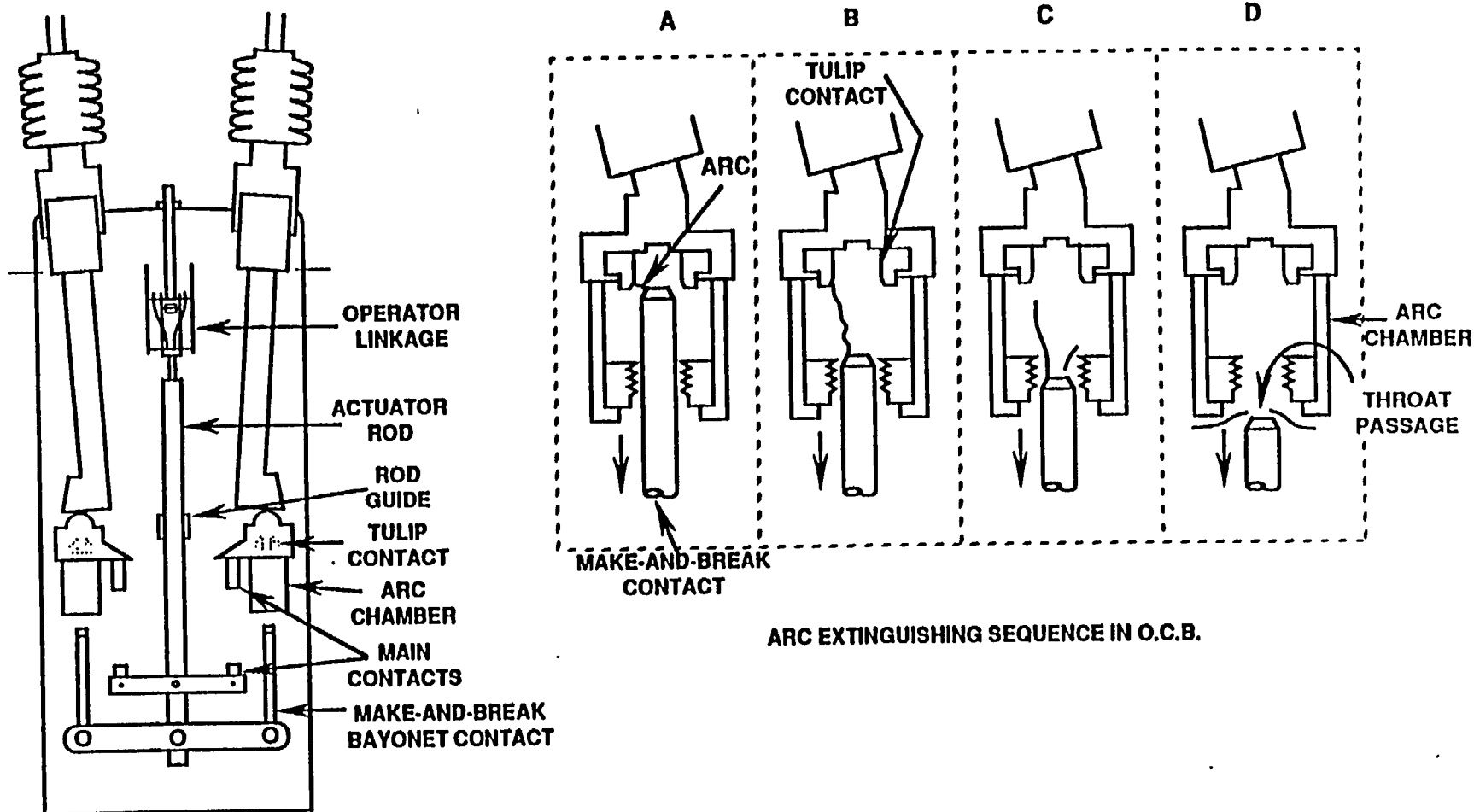


Figure 9 - 15. Oil Circuit Breaker

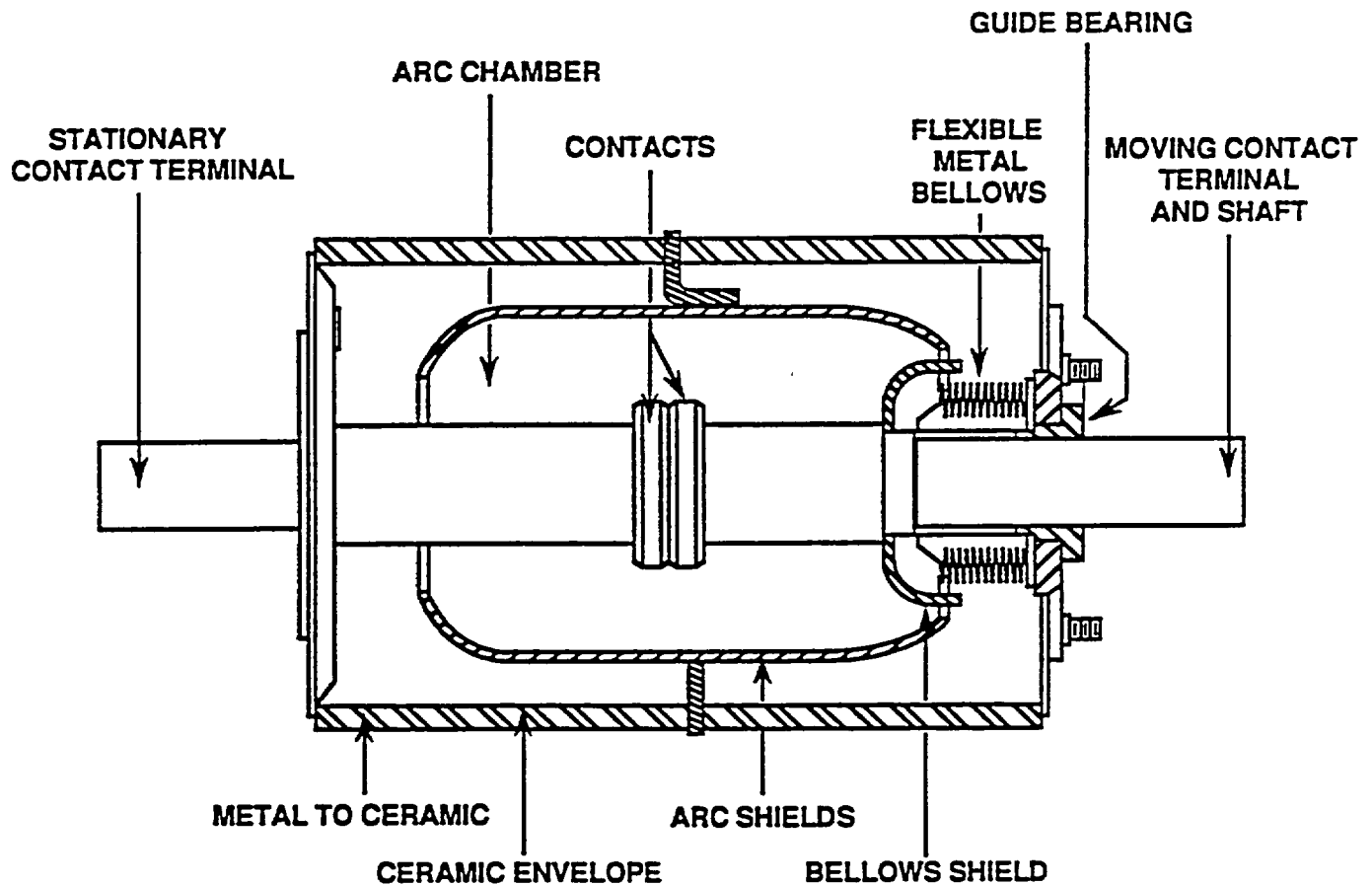
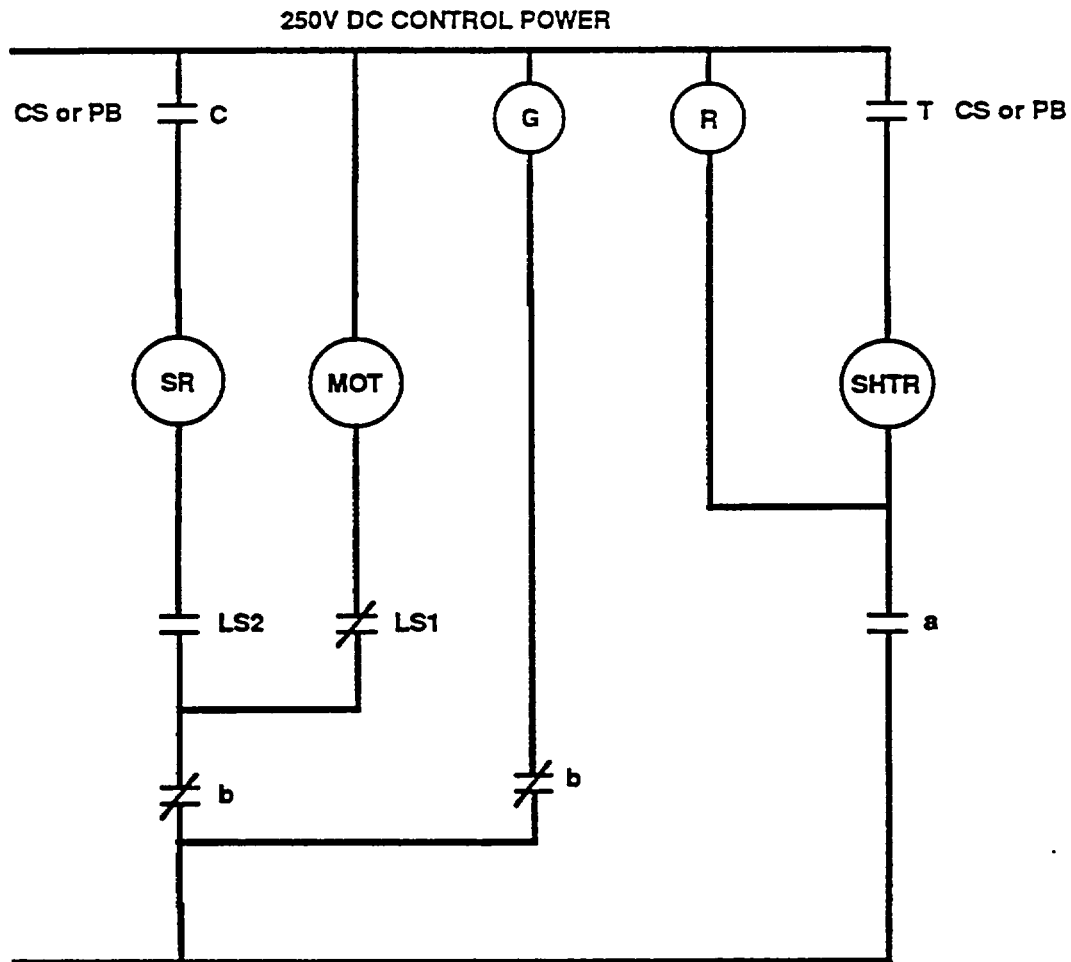


Figure 9 - 16. Vacuum Circuit Breaker

**LEGEND**

LS1, LS2	LIMIT SWITCHES FOR CLOSING SPRING
MOT	MOTOR FOR SPRING CHARGING
SHTR	SHUNT TRIP COIL (FOR TRIPPING BREAKER)
SR	SPRING RELEASE COIL (FOR CLOSING BREAKER)
C CS or PB	CLOSING CONTROL SWITCH OR PUSHBUTTON
T CS or PB	TRIPPING CONTROL SWITCH OR PUSHBUTTON
G	GREEN (OPEN) INDICATING LIGHT
R	RED (CLOSED) INDICATING LIGHT
a,b	BREAKER AUXILIARY CONTACTS

Figure 9 - 17. Breaker Control Circuit

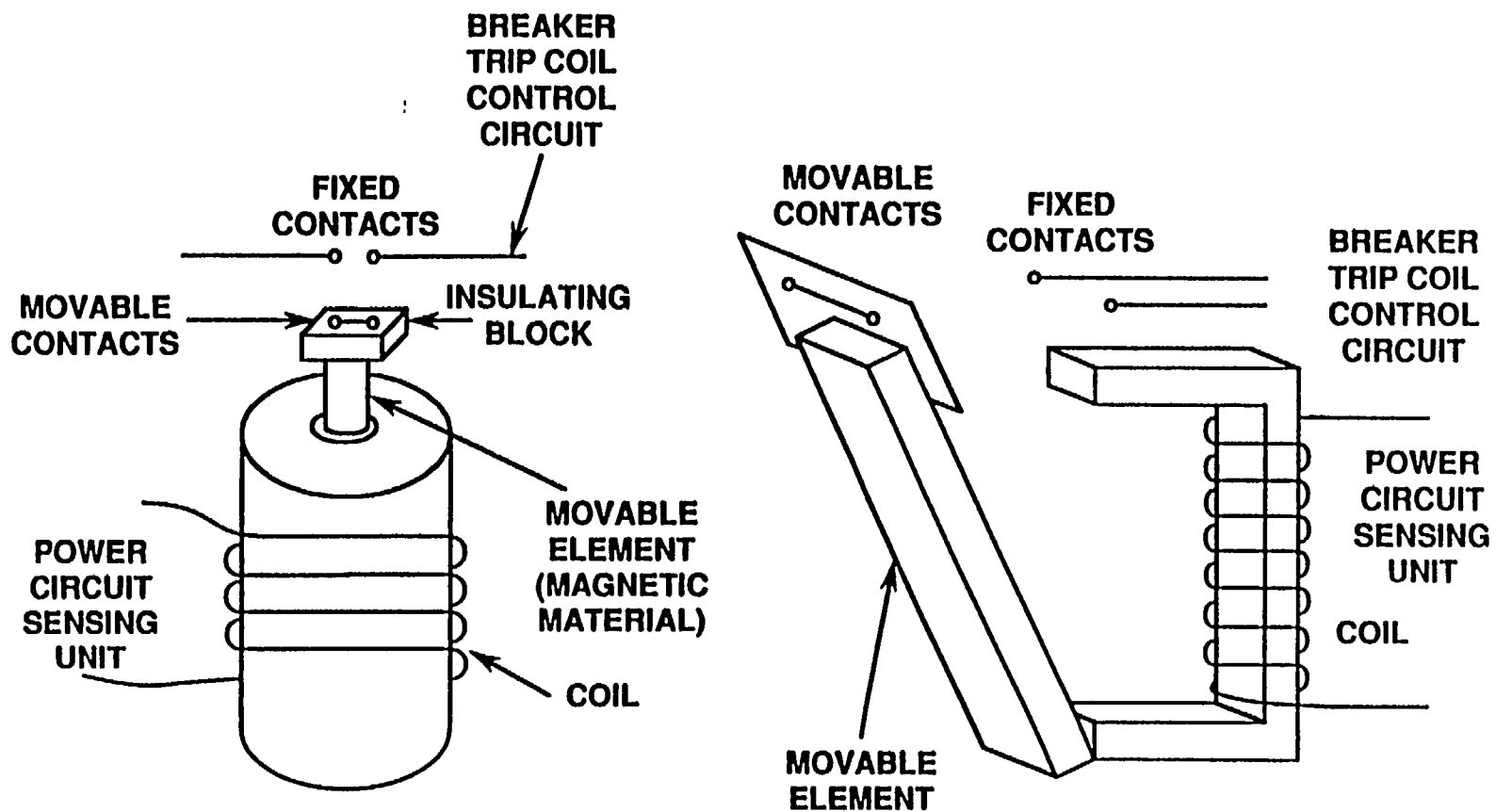
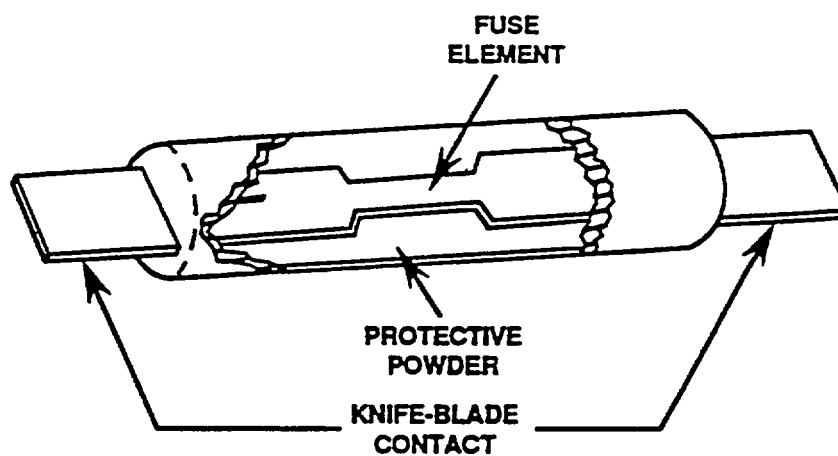
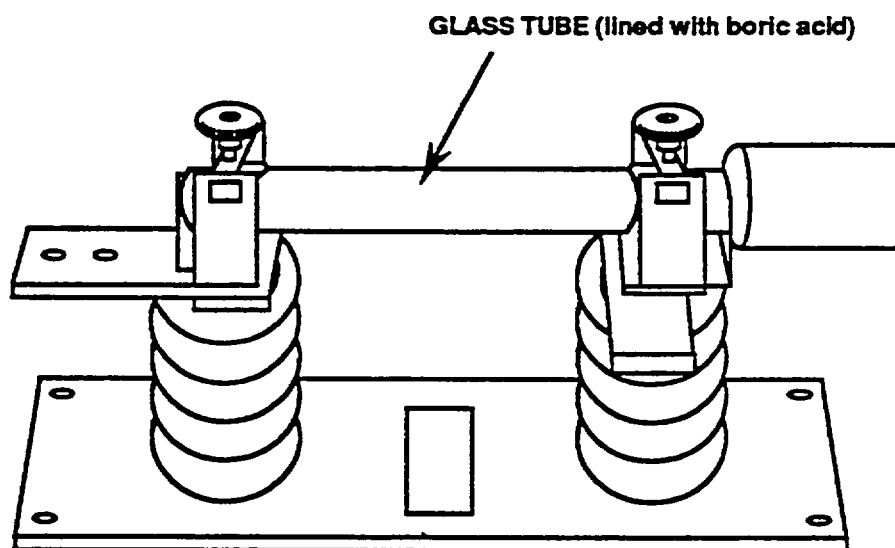


Figure 9-18. Protective Relays



LOW-VOLTAGE CARTRIDGE FUSE



BORIC ACID HIGH-VOLTAGE FUSE

Figure 9-19. Typical Fuses

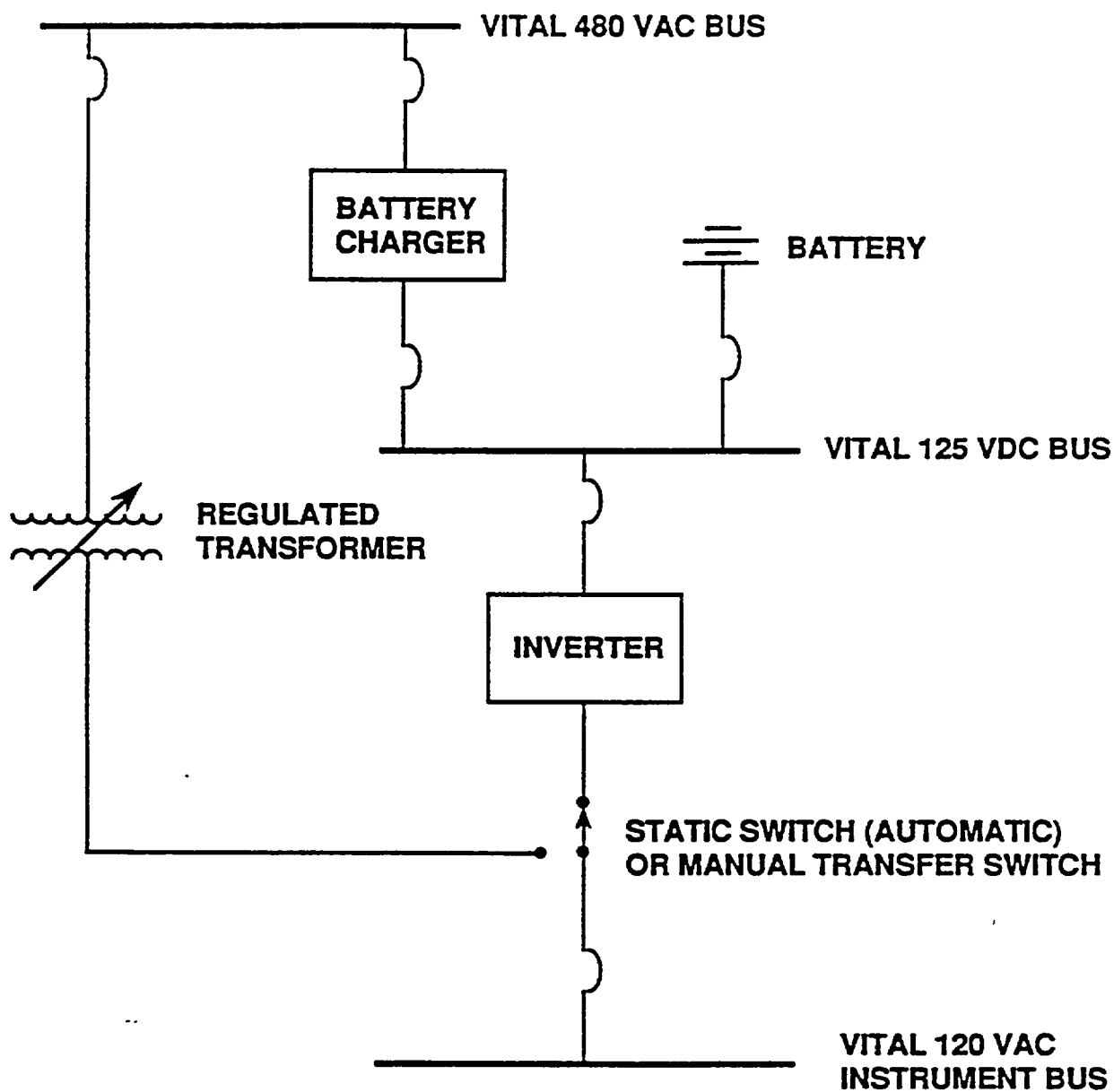
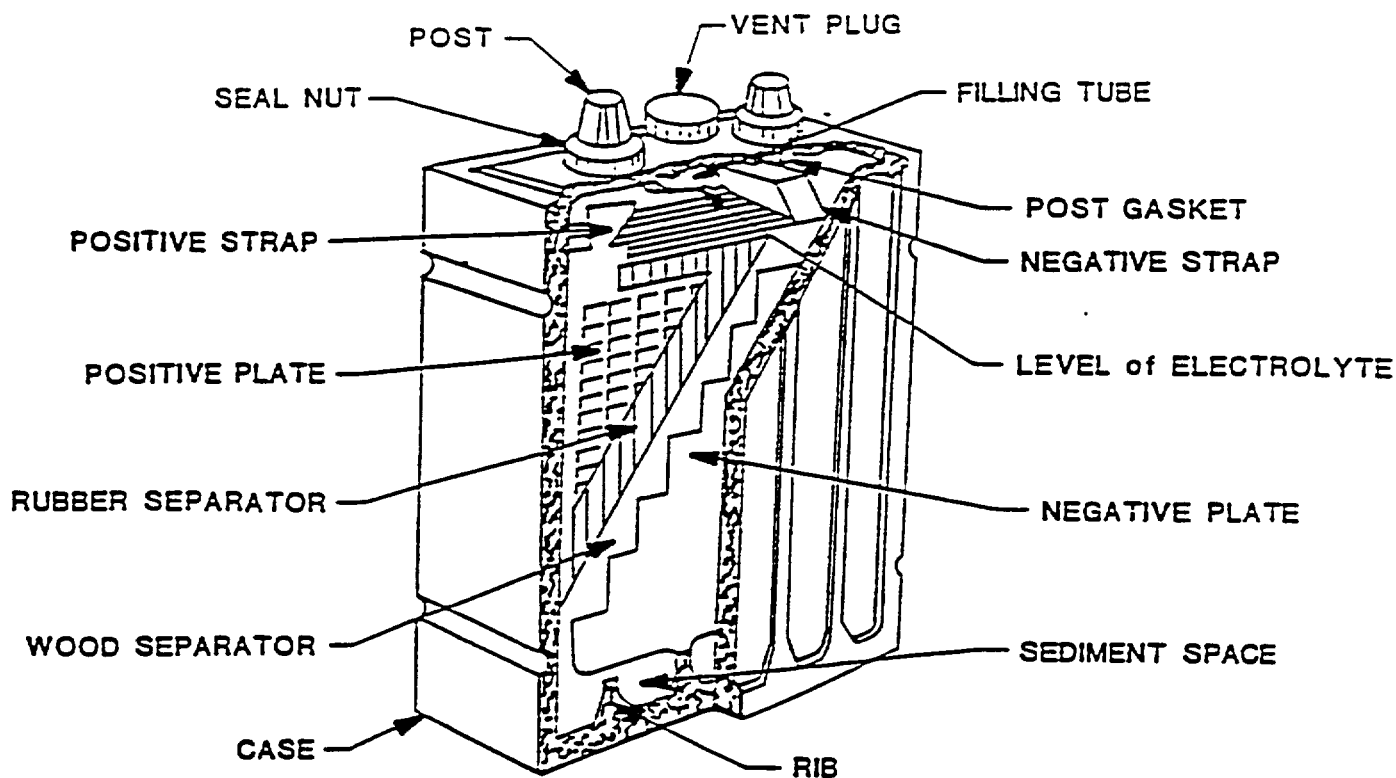
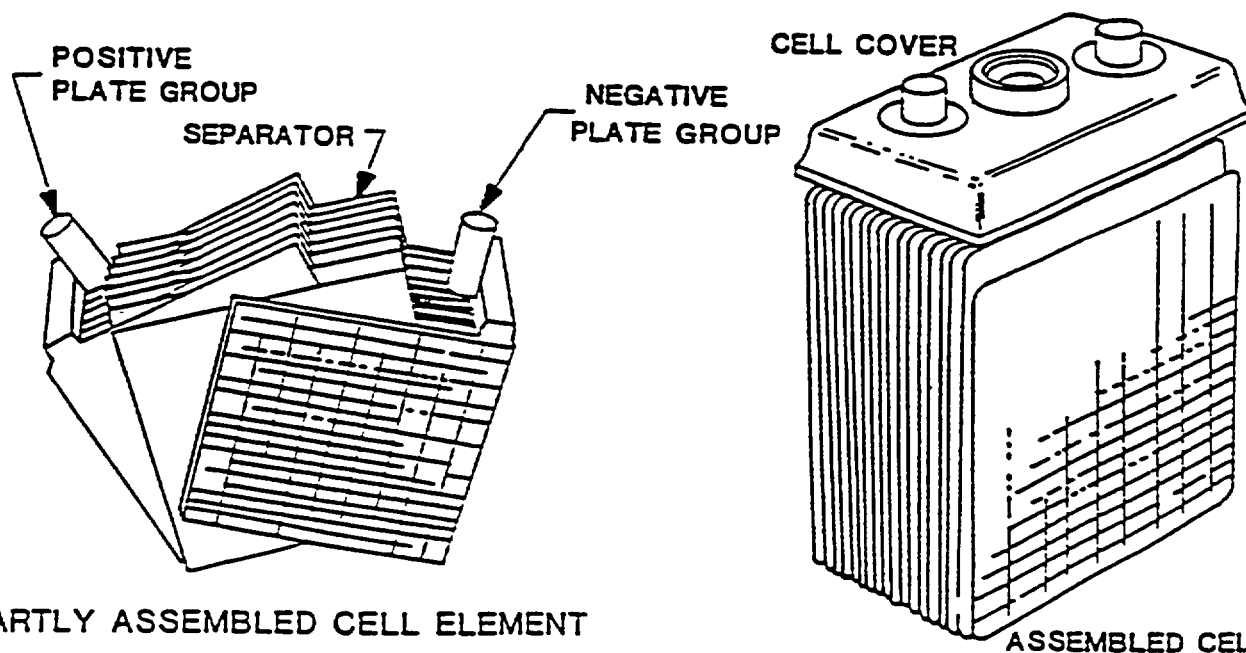


Figure 9-20. Uninterruptible Power Supply



A. SECONDARY CELL - Cross Sectional View



B. PARTLY ASSEMBLED CELL ELEMENT

C. ASSEMBLED LEAD-ACID CELL

Figure 9-21. Lead-Acid Battery Construction

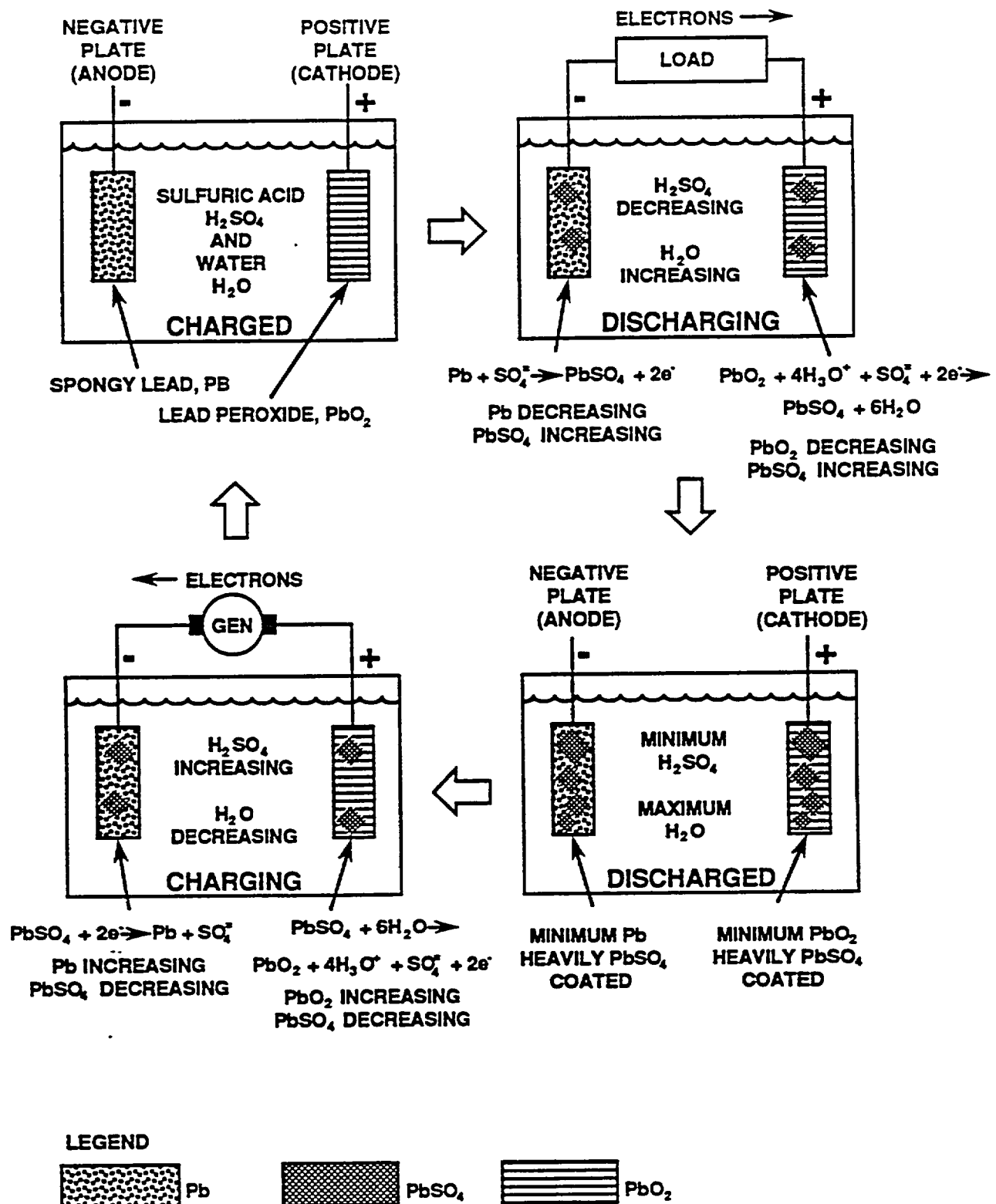


Figure 9 - 22. Basic Chemical Action of a Lead-Acid Storage Battery

10.0 PIPING

Learning Objectives

After studying this chapter, you should be able to:

1. Explain the following piping terms:
 - a. Nominal pipe size
 - b. Pipe schedule
2. Describe the functions of piping snubbers.
3. Describe the purpose of the following valve components:
 - a. Disk
 - b. Seat
 - c. Body
 - d. Bonnet
 - e. Stem
 - f. Packing
 - g. Actuator
 - h. Yoke
4. Describe attributes and application of the following valve types:
 - a. Gate
 - b. Globe
 - c. Check
 - d. Stop-check
 - e. Butterfly
 - f. Safety
 - g. Relief
 - h. Solenoid
 - i. Plug/Ball
 - j. Diaphragm
5. Define the following pressure-relief valve terms:
 - a. Blowdown
 - b. Chatter
6. Describe the attributes and application of the following valve actuator types:
 - a. Manual
 - b. Electric
 - c. Pneumatic

d. Hydraulic

7. Describe various terms concerning motor-operated valves:
 - a. Seal-in feature
 - b. Throttle feature
 - c. Position limit switches
 - d. Torque limit switches
 - e. Worm
 - f. Clutch

10.1 General Description

Piping is a term used to describe a connected assembly of pipe or tubing, valves, fittings, and related components forming a system (or part of a system) for transferring gases and liquids. It is more difficult to define the difference between pipe and tubing. In regular, commercial usage, no clear distinction is made. The manufacturer decides whether the tubular product is called pipe or tubing. In modern power plant application, the distinction is generally made by custom. The boiler and heat exchangers are constructed from tubing, and the steam and water are transported in pipes. Generally, tubing is internal to components and piping is external.

For the purposes of this discussion, no specific distinction will be made between pipe and tubing.

10.2 Pipe

Power plants use many different types of pipe. The type used for a specific application depends on the temperature, pressure, and corrosive effects of the liquid or gas to be transported. The pipe materials are selected on the basis of the requirements found in the various codes and standards.

10.2.1 Piping Standards

Standardization in the piping industry is the function of many groups, among whom are the American Society for Testing and Materials (ASTM), the American National Standards Institute (ANSI), the American Water Works Associa-

tion (AWWA), and the Pipe Fabrication Institute (PFI); in addition, specifications have been issued by several governmental agencies to cover work on federal installations.

The ASTM has as its aim the "promotion of knowledge of materials of engineering, and standardization of specifications and methods of testing." It is concerned with chemical and physical properties of piping (and other materials or products) as delivered from the fabricating mill.

The ANSI deals with overall piping systems. It standardizes dimensions, sets permissible stress values as functions of temperature, establishes working formulas for determination of wall thickness as determined by pressure and material at a given temperature, specifies general character of construction of valves and fittings, deals with the support, anchoring, and flexibility of a piping system and, in general, sets up a code of minimum requirements for the safety and reliability of a system. The work done by this organization has culminated in hundreds of standards for individual materials, published in several issues of its Code for Power Piping and related publications.

The AWWA was one of the first groups to realize the importance and advantage of standardization of cast-iron pipe and fittings. Its standard, first published in 1908, has been superseded by ANSI publications.

PFI has been active in preparation of standards dealing with shop fabrication, particularly in standardizing the techniques for preparation of pipe ends prior to welding.

10.2.2 Pipe Size and Schedule

As shown in Table 10-1, pipe size is given by a nominal pipe size, which is a "round number" or approximation of the pipe diameter. Table 10-1 lists the nominal pipe size and the inside and outside diameters for standard pipes. When the nominal pipe size is 14 inches or larger, nominal pipe size and *outside* diameter are equal. When the

nominal pipe size is 12 inches or smaller, nominal pipe size approximates the pipe *inside* diameter, depending on the pipe wall thickness.

In addition to diameter, the other primary pipe dimension is wall thickness. The designations STD, XS, and XXS in Table 10-1 refer to standard, extra strong, and double extra strong pipe, respectively. These designations of pipe wall thickness will sometimes be encountered in plant piping systems. These designations were in common use years ago, but there were no provisions for thin-walled pipe and no intervening standard thicknesses among the three designations. Schedule numbers allow for specifying more exactly the wall thickness and, therefore, the pipe strength needed to meet actual use requirements. The pipe schedule number refers to the pipe wall thickness.

The third through fifth columns of Table 10-1 relate iron pipe designations to the schedule numbers for steel and stainless steel. The last two columns in Table 10-1 give wall thickness and inside diameter. (Note: This is not a complete pipe data table, as found in industry standards. Other data that may be found include weight of pipe per foot, cross-sectional area, and volume (cubic feet) per running foot.)

Schedule number is determined approximately by the equation:

$$\text{Schedule No.} = 1,000 \times P/SE,$$

where

P = operating pressure, and

SE = allowable stress range of pipe material.

Example: Find the required schedule of ASTM A-155 Class 1 pipe operating at 850 psi and 650°F.

Table 10-2 lists the SE value as 11,250 psi using the above equation:

$$\text{Schedule No.} = 1,000 (850/11,250) = 75.6$$

In this example, schedule 80 would be specified. major radiation source.

10.2.3 Pipe Materials and Applications

Piping is available in both ferrous and nonferrous materials. Cast iron and steel represent the ferrous class; brass, copper, aluminum, and lead are nonferrous metals which have wide applications as piping materials. Concrete, wood, tile, and plastic have found general acceptance for specific usages.

10.2.3.1 Carbon-Steel Pipe

Carbon steel is the most widely used piping material in a modern power plant. Carbon steel is used unless the temperature of the fluid is high (above 750°F) or the fluid is corrosive or abrasive. When it is necessary to eliminate the possibility of contaminating the fluid with rust or scale, other materials such as copper or stainless-steel pipe are used for lubricating systems, instrument air systems, control air systems, and water sampling systems. It is critical that these systems be maintained free of foreign particles and contamination. The bearings in the lubrication systems can be scored or scratched by foreign debris, and the small orifices in instrument air systems can become clogged.

A clogged control air system will not perform its function, and water samples that are contaminated will not yield valid test results. Thus, these systems require extremely pure conditions, more than steam systems, for example.

10.2.3.2 Stainless-Steel Pipe

Stainless-steel pipe is normally used where operating conditions limit the use of carbon steels. These conditions include high temperature and the presence of corrosive fluids. Systems where rust and scale must be prevented may also use stainless-steel pipe. Stainless steel is used throughout the Reactor Coolant System where low corrosion rates are imperative. Excess corrosion products can be transported to the reactor and become a

10.2.3.3 Chromium-Molybdenum Pipe

Chromium-molybdenum-alloy steel pipe is also used in some high pressure, high temperature systems. This type of pipe is available with different percentages of chromium and molybdenum. The chromium alloy of steel resists corrosion and has increased strength and creep resistance. Common upper limits of pressure and temperature for chromium-molybdenum pipe are approximately 1500 psig and 875°F.

10.2.3.4 Cast-Iron Pipe

Cast iron is one of the oldest pipe materials in use. Although once used exclusively for power plant piping, cast-iron pipe today is used only for water or gas distribution and sewage disposal because its resistance to soil corrosion makes it a good underground pipe.

10.2.3.5 Concrete Pipe

Concrete pipe is typically used for large underground piping, such as sewage and circulating water systems. The pipe is constructed of concrete reinforced longitudinally with bars and transversely with wire mesh and steel bands. It is manufactured in sections of specified length and is designed to provide for interlocking sections to form a continuous line of pipe that is free from leakage or seepage.

10.3 Pipe Hangers, Supports, and Snubbers

Piping must be supported to prevent its weight from being transferred to attached equipment. Pipe hangers prevent the sagging of pipe but allow for slight movement of piping that results from expansion and contraction and normal vibration. The hangers and supports must be designed for piping movement in all directions.

Hangers must carry the weight of pipe, valves, fittings, and insulation, plus the weight of the fluid

inside the pipe. Power plant personnel should be familiar with the different types of pipe hangers and be able to determine when undue stress is being exerted on a hanger.

The hangers and supports most commonly used in power plants are:

- adjustable hangers,
- variable spring hangers,
- constant supports,
- roller stand supports, and
- snubbers.

10.3.1 Adjustable Hangers

Adjustable hangers (see Figure 10-1) do not allow for any vertical movement of the system. A simple strap may be used if horizontal pipe motion is not a factor; a roller can be used if some horizontal movement is expected. These hangers are also commonly referred to as rigid hangers.

10.3.2 Variable Spring Hangers

Variable spring hangers (see Figure 10-2) permit piping to move up or down without suddenly disturbing the load distribution. This type of hanger supports pipe runs that may be subjected to slight vertical movements. Variable spring hangers also support piping that may be shifted horizontally as a result of the movement of attached equipment or piping. An example would be thermal expansion of a vertical piping run that is followed by a 90° elbow and a horizontal run.

Variable spring hangers also provide a cushion for the piping system. Plant personnel should observe these hangers closely to make sure the load is balanced and the springs are not fully compressed ("bottomed"). Each hanger is equipped with a load indicator and a load scale. The scale is normally marked with an "H" or "C" to denote the correct load reading when the supported piping is hot or cold.

10.3.3 Constant Supports

Constant supports (see Figure 10-3) have a coiled helical spring that moves as the pipe moves to provide constant support. This type of support is used when vertical movement is substantial. Critical piping systems such as the main steam system usually have constant supports.

The constant support is factory adjusted to support a specified load. However, spring compression may be readjusted by tightening or loosening the spring tension. Constant supports should be inspected periodically to prevent the spring from being fully compressed. Constant supports are also fitted with the load indicator and markings on the scale.

10.3.4 Roller Stand Supports

Roller stand supports (see Figure 10-4) may be bolted to beams or floors; they may be adjustable or nonadjustable. The adjustable type can be raised or lowered by four adjusting screws to match pipe position. This type of support allows for unrestricted horizontal movement along the piping run. A typical use of roller stand supports would be to support the long horizontal run of a piping system that is expected to expand and contract as it warms and cools.

10.3.5 Snubbers

Snubbers (see Figure 10-5) are special application supports that are designed to allow gradual movement such as thermal growth, but resist sudden pipe movement from events such as earthquakes, fault loading (pipe whip), and vibration or shock. Many piping systems in a nuclear power plant must remain intact under seismic events or accident conditions to ensure plant and equipment reliability. These systems make extensive use of snubbers.

The most common type of snubber is the hydraulic type. In this design, the movement of a pipe drives a piston in the cylinder of the snubber.

The piston forces hydraulic fluid to move past a spring-loaded check valve. For normal movement such as during thermal growth or expansion, the fluid movement is small and is not restricted by the check valve. If the pipe movement is rapid, as during an earthquake, the sudden increase in hydraulic pressure at the check valve will seat the check valve and create a "hydraulic lock" on the operating piston. A small "bleed valve" is provided to slowly release the hydraulic lock to allow normal operation to resume. Most snubbers are a double-acting type to restrain the pipe in both directions.

Plant designers have often specified snubbers for other than rigid seismic supports to preclude the need to redo thermal flexibility analysis. This approach is more expedient and often more economical than an extensive re-analysis. It is also more conservative, assuming the snubbers function properly. Procedures such as this have yielded adequate support under dynamic (rapid) loadings and lower stress during normal operations. However, subsequent operational problems have raised questions about snubber availability and have led to tremendous increases in surveillance frequency to ensure their availability.

Snubber failures have occurred for many reasons. Contaminated hydraulic fluid changes clearances and bleed rates; failed seals and "O" rings destroy the hydraulic action; cracked reservoirs and loose fittings cause hydraulic fluid loss; and freezing or overheating can damage the internals. In short, the small clearances and complicated design have produced failure rates far in excess of expectations.

Although snubbers have only minor impact for normal operations (e.g. increased surveillances and maintenance), a heavier penalty can be exacted under earthquake loadings. Under such dynamic loadings the snubbers lock up and stiffen the piping system. By increasing the stiffness, the relative displacement loads resulting from differential support movements may actually be increased. Adding snubbers beyond an optimum

number could make the system more susceptible to the event they were designed to protect against.

10.4 Valves

It is often necessary to stop or control the flow of a fluid (vapor or liquid), into, through, or from a pipeline. This is accomplished by means of a valve; a device consisting of a body containing a passage with a suitable means of tightly closing the passage by closing a disk, plug, or ball against a seating surface surrounding the passage.

10.4.1 Common Valve Parts

Figure 10-6 illustrates a basic gate valve. It also illustrates the parts that are commonly found in most valves. While their size and some design features may vary, the function to be performed by the part must be performed no matter what variables are involved (material of construction, size, pressure of liquid or gas in the system, etc.). Fluid flow through the piping system is throttled, controlled, or shut off entirely by the relative position of the valve disk and its seat in the valve body. A simple example is a cork (disk) positioned in a bottleneck (seat) that can be positioned partially in the neck to throttle flow, withdrawn for full flow, or fully inserted to stop flow from the bottle.

10.4.1.1 Valve Disk

The disk is the movable closure part that seals against the stationary seat to stop flow. The disk provides the capability to regulate (throttle) or stop system flow through the valve. System flow is stopped when the disk is inserted into and is in full contact with the valve seat. The disk is attached to the valve stem, which moves the disk to open, close, or throttle the flow through the valve. The disk found in a gate valve is one of four basic methods employed to control flow through a valve:

1. Move a stopper, into or against an orifice such as is done in the globe and needle type valves.

2. Slide a flat, cylindrical, or spherical surface across an orifice such as is done in the gate, plug, ball, slide, or piston valve.
3. Rotate a disk or ellipse about a shaft extending across the diameter of a circular casing as is done in a butterfly valve.
4. Move a flexible material into the flow passage, such as is done in the diaphragm and pinch valves.

10.4.1.2 Valve Seat

The seat is the stationary half of the closure surface against which the valve disk seals to stop or throttle system flow. The valve seat is an integral part of the valve body. In some valves, the body itself is machined to provide the seating surface. In other valve designs, the valve seat is screwed or welded into the valve body. In any case, the valve seat must be a very smooth and hard surface to prevent leakage and resist wear.

10.4.1.3 Valve Body

The body forms the major part and outline of the valve. It supports all the other valve parts. The valve body contains the valve seat that receives the valve disk to close off or throttle the flow. The body is constructed so that when the valve is completely assembled, the valve will prevent system leakage whether it is open or closed. The valve body is connected to the system by bolting (flanges), threading (screwed connection), or welding it to the piping.

10.4.1.4 Valve Bonnet

The bonnet is the closure head on the valve body. Without a bonnet and other internals discussed below, the valve body is merely a cavity containing the seat surface. The valve bonnet supports the stem, disk, and actuator. The valve bonnet is connected to the valve body by bolting, threading, welding, or a combination of the three.

10.4.1.5 Valve Stem

The stem moves the valve disk onto and off the valve seat. Valve stem motion may be manual (handwheel or bar) or power operated (electric, hydraulic, or pneumatic).

There are two common types of stems for gate, globe, and angle valves. Valve stems are classified by whether they move up and down as the valve is opened and closed, and whether the stem threads are inside or outside the system fluid. A stem that rises (when the valve is opening and the disk is moving out of the seat) and falls (when the valve is closing and the disk is moving into the seat) is called a rising stem. Figure 10-6 is a non-rising stem valve, and Figure 10-7 is a rising stem valve. If the stem threads are internal to the valve and in contact with system fluid, the valve has an inside screw; if the threads are not in contact with system fluid, the valve has an outside screw.

A valve with a rising stem and an inside screw may not be suitable for a location having little clearance or in a system carrying corrosive fluid. Outside screw stems are often used with large valves and are always recommended for severe service conditions.

10.4.1.6 Valve Packing

Because the valve stem must pass through the valve bonnet to move the disk in and out of the seat, a means to prevent fluid leakage is required. Packing is special malleable material that is forced around the stem where it passes through the bonnet. The stuffing box encloses the packing and prevents leakage around the stem. Fluid leakage along the stem can usually be controlled by tightening the packing nut or gland nuts. This squeezes the packing tighter against the stem.

10.4.1.7 Valve Actuator

The actuator (sometimes called operator) moves the stem to seat (close) or unseat (open) the disk in the valve seat. The actuator may be a

handwheel, bar, or power operator. The actuator may be supported by the stem itself (handwheels and bars), or the actuator may be supported by the valve bonnet (power actuators). Specific types of valve actuators or operators will be discussed in other sections of this chapter.

10.4.1.8 Valve Yoke

A yoke (example shown in Figure 10-8) is provided when the valve stem and actuator need mechanical support to prevent the stem from being bent due to the force exerted on the stem when the valve is operated. The yoke is the support arms that extend from the valve bonnet to encircle the stem near the valve actuator. The arms are called the yoke because they are often shaped like the yoke used for oxen. Large outside screw valves normally have a yoke to support the stem and actuator (particularly when the actuator is a motor operator). Such valves are called outside screw and yoke (OS and Y) valves.

10.4.2 Gate Valves

Gate valves (see Figure 10-6) are designed to operate either fully open or fully closed. They should not be used to regulate, adjust, or throttle system flow. When gate valves are partially open and being misused to regulate, adjust, or throttle flow, the valve can be damaged. System flow causes rapid erosion of the disk and seat whenever the valve is not fully open.

The major parts of a gate valve are body, bonnet, stem, and seat rings. Sometimes the disk of a gate valve is referred to as the gate because of its shape. It is in the form of a wedge and it is raised or lowered into a slot-type seat. In most gate valve designs, the seat is made up of seat rings on each side of the disk.

The valve gate is raised or lowered by the valve actuator. The gate is lowered into the flow path to stop flow. The gate is lifted out of the flow path to allow flow. The gate is forced against the valve seats as the valve is closed, thus providing a

tight seal. When the valve is fully open, the gate is totally out of the flow path and does not obstruct the flow.

A variation of the gate valve often used in heated piping systems is the split-disk type. In the split-disk type, the disk is composed of two separate halves, each with its own seat. Springs force the two disk halves apart and against their seats. This arrangement prevents disk binding when the piping system expands and contracts with temperature changes.

The gate valve has two advantages: (1) very little flow restriction when the valve is full open and (2) long life span. Disadvantages of gate valves include: (1) poor throttling ability; (2) poor operation against high differential pressure; (3) longer stroke times as compared with other valve types due to the greater stem movement necessary to remove the disk from the flowpath; and (4) packing leakage is more difficult to control.

10.4.3 Globe Valves

The globe valve (see Figure 10-7) consists of a disk that is forced into a tapered seat. The angle used and the taper of the disk and seat vary with valve size and the kind of service to which the valve is applied. Globe valves are used when the flow is to be regulated or throttled. The globe valve seat and disk are not damaged as readily as gate valves by the throttling action. Globe valve parts are also easier to repair and replace. The four most common designs of globe-type valves are:

- metal disk with narrow conical seat,
- plug disk,
- angle, and
- needle.

10.4.3.1 Metal Disk With Narrow Conical Seat

This type of globe valve (see Figure 10-8) usually has a ball-shaped surface on the disk and a conical flat seating surface in the body, and is

generally what is referred to as the common type of globe valve.

Because of the narrow seating-surface area, this valve is easily made tight, can be refaced or reground readily, and is adaptable to many types of service. The principal disadvantage of this type of seat is that very hard dirt or foreign matter may scratch the seating surface, causing leakage. The result of such leakage is wire-drawing action of the fluid, which will destroy the seat in a very short time. Even though the dirt may not be hard enough to cut into the metal, if it holds the disk away from its seat and the disk is allowed to remain in this position, the fluid leaking through the valve seat and disk will cut a groove in the seat ("wire drawing"). Once a seat is wire drawn, leaktight valve closure is impossible. Wire-drawing action often occurs in a dripping water faucet. The hot water under pressure "wire draws" (cuts) a groove in the valve seat. Because the typical globe valve is susceptible to the wire-drawing action of the fluid, it should not be used in a close throttling or fine tuning application.

10.4.3.2 Plug Disk

The plug disk design is advantageous because it (1) throttles flow more effectively than other designs and (2) resists the wire-drawing action of high velocity flow. This construction comprises a plug-shaped disk and mating seat, which produce:

- A gradual increase or decrease in the distance between the seat and disk surfaces when the valve is slowly opened or closed. This causes a gradual change in flow area, thereby providing a throttling action.
- A wide contact area between disk and seat surfaces. The effect of wire drawing is greatly minimized because cutting always starts at outer edges of a seating surface. In addition, any indentions in the seat caused by hard particles of foreign matter are unlikely to extend across the entire disk or seat surfaces and, therefore, are not apt to

cause leakage.

If top-grade seating material are used in this design, it is extremely difficult to find another type of valve that surpasses the service life of a plug-disk globe valve.

10.4.3.3 Angle Valve

The angle valve (see Figure 10-9) has the same disk variations as other globe-type valves: plug disk and conventional disk. The valve will reduce turbulence, restriction of flow, and amount of pressure drop of the fluid because the flow makes fewer changes in direction than in other globe-type valves. The angle valve cuts down on piping installation time, labor, and materials, and reduces the number of joints or potential leaks by serving both as a valve and a 90 degree elbow.

10.4.3.4 Needle Valve

Needle valves (see Figure 10-10) are used for fine control of flow in small diameter piping. The name needle valve is derived from the sharp pointed conical disk and matching seat. Needle valves come in straight and angle patterns, and are used in steam, water, oil, gas, light liquid, fuel oil, and similar service. The primary purpose of the needle valve is precise throttling. The design of the seat and disk makes it a more efficient throttling valve than the plug valve in small-diameter piping. The stem threads are usually finer than most valves, so several rotations of the stem are required to increase or decrease the opening through the seat. This improves the throttling characteristics of the valve.

10.4.3.5 Advantages and Disadvantages of Globe Valves

The advantages of globe valves are (1) flow can be restricted or throttled without damage to the valve; (2) the valve flow path may be arranged such that system pressure in the reverse direction will tend to seat the valve tighter; and (3) valve parts are easier to replace for service or repair. The

general disadvantages of all types of globe valves are (1) they provide increased resistance to flow; (2) high system flow increases pressure under the disk and more force is required to close the valve; and (3) foreign matter may cause plugging of the valve as a result of the several directional changes in the flow.

10.4.4 Check Valves

Check valves are designed to permit fluid flow in one direction only. As system flow stops and starts to reverse, the check valve closes. The three basic types of check valves are swing-check, lift-check, and stop-check valves. Check valves are extremely important to proper functioning of any piping system because of (1) their quick automatic action and (2) their sensitivity to changes in flow conditions. Furthermore, they prevent dangerous or undesirable backflow in a line when two or more fluids are being supplied to a common point at different pressures.

10.4.4.1 Swing-Check Valve

The swing-check valve (see Figure 10-11) has a hinged disk that swings when operating. Flow from inlet to outlet swings the disk open. Reduced system flow allows the disk to partially close as a result of gravity. This design feature helps prevent the valve from "slamming" on flow reversal (outlet to inlet). This reduces the shock ("waterhammer") to valve seat and disk, as well as to system piping. Swing-check valves offer little resistance to flow when open. Therefore, this valve is used in systems where pressure loss in the open direction must be kept to a minimum.

Swing-check valves usually have replaceable components. Washers fitted on the top of the disk take most the valve wear, extending the life of the valve seat. A loose-fitting hinge pin allows easy closure as flow drops.

10.4.4.2 Lift-Check Valve

The lift-check valve (see Figure 10-12) is

designed so that flow through the valve lifts the disk away from its seat. Gravity, or back pressure, holds the disk to its seat when closed. Because flow changes direction as it passes through the valve (as in a globe valve), these valves cause considerable pressure drop. They are designed to permit full disk lift under normal operating conditions. Sometimes a free-floating ball is used instead of a plug disk. The ball never seats twice in exactly the same way. Each seating presents a new ball surface, cutting down on wear and prolonging valve life.

In the lift-check valve, the disk (plug) is attached to slide rails on a fixed stem. The disk is free to open or close with no stem motion. The valve disk "lifts" off the seat when the flow is from inlet to outlet. When the flow is reversed, the disk seats, preventing flow.

Some lift-check valves have an internal pressure-equalization passage or pipe connecting the bonnet area above the valve disk to the valve outlet area. This passage will vent off any pressure "lock" that might build up within the bonnet above the disk when the disk is lifted by flow in the normal direction. When normal flow is lost or reversed, and the disk starts to drop toward the seat, the internal passage supplies valve outlet pressure to the area above the disk to prevent formation of a vacuum "lock" that might hinder the valve closing operation.

10.4.4.3 Stop-Lift-Check Valve

A special application of the check valve is the stop-lift-check valve (see Figure 10-13). When the stem is withdrawn, the disk is free to lift or close, depending on the direction of flow, just as a typical lift-check valve. After system flow through the valve is stopped, the stem may be inserted in the disk by the valve actuator.

When the stem is inserted in the disk, it forces the disk tight against the seat. In this position, the valve serves as a stop valve, and all flow is stopped. A typical location for this valve is in a PWR

feedwater line, where it serves as a feedwater stop-check valve to the steam generator inlet.

10.4.5 Butterfly Valves

Butterfly valves (see Figure 10-14) are extremely durable, efficient, and reliable. The butterfly valve derives its name from the wing-like action of its disk, which moves from parallel (open) to flow through the valve to a right angle (closed). Thus, one-quarter turn of the stem and disk is all that is required to go from fully open to fully closed.

Butterfly valves use a variety of materials for seat linings and disk surfaces. The seat can be made of a resilient lining for leak tightness, or of a harder, long-wearing material for extended life. Where high temperatures preclude the use of the resilient lining, the disk itself can have a ring (similar to a piston ring) to minimize leakage.

The light weight of butterfly valves often permits their use in piping systems without separate support. Butterfly valves are relatively inexpensive, fit into tight places, and present little obstruction to system flow when fully open.

A disadvantage of butterfly valves is their inability to seal tightly when there are high pressure differences. They are also unsuitable for throttling applications.

10.4.6 Safety and Relief Valves

Safety and relief valves are essential to power plant operation. These valves provide automatic over-pressure protection for piping systems and equipment.

10.4.6.1 Safety Valves

There are many kinds of safety valves, all designed to "pop" (open fully) when a specific or "set" pressure is reached. The valve should "pop" open suddenly, and remain wide open and at full flow until a specified pressure drop or reduction

has occurred. This pressure drop is referred to as the blowdown, which can be adjusted, and is normally specified as a percentage of the valve lift pressure. When the blowdown has been completed, the valve will snap shut. Safety valves must close tightly and remain closed without "chatter." (Chatter is the repeated partial opening and closing of a safety or relief valve.)

The lift of a safety valve disk is caused by pressure of the fluid (or gas). The safety valve is designed to *pop fully open* once the set pressure is reached. When the valve starts to open, the area exposed to the pressure is increased, causing a greater force to be exerted against the spring pressure, and the valve pops fully open. The increased force is obtained by an effective increase in exposed disk area as the disk rises. The venturi effect of the inlet nozzle also adds to the lift force as the steam expands past the throat of the nozzle. The safety valve also closes rapidly and completely because of this relationship in reverse. As the system pressure drops (pressure is being relieved), the spring tension overcomes the decreasing lift force and the valve starts to close. The closing action decreases the area of lift force, which allows the spring to suddenly overcome the lifting force snapping the valve shut.

10.4.6.1.1 Safety Valve Discharge

Suitable arrangements must be made to ensure that the discharge from safety valves is safely removed and dispersed. Four critical design criteria for a safety valve escape system, regardless of fluid type being handled, are:

1. The fluid must not discharge into the atmosphere at a point where there is a conceivable danger to personnel safety.
2. The escape system must provide for thermal movement of the pressure source relative to the discharge point and thermal expansion of the discharge system. Therefore the safety valve is not subject to any external forces on its body or back pres-

sure on its steam chest greater than the maximum defined by the valve maker.

3. Materials used must be corrosion resistant, particularly where they are exposed to the elements.
4. The steam blow must be silenced in accordance with local pollution regulations.

Two types of high pressure steam safety valves in general use are (1) nozzle reaction and (2) huddling chamber.

10.4.6.1.2 Nozzle Reaction Safety Valve

As explained in section 10.4.6.1, during the opening phase of any safety valve, the spring force keeping the valve closed must be counteracted by a greater force on the steam or gas pressure side. But as the disk rises, the spring load increases from compression, so the total force needed to obtain full lift must also increase. In the nozzle reaction valve (see Figure 10-15), the valve internals cause the lifting force to be greatest at or near the end of the lift, thus giving full bore lifts even with a small volume of relieving steam.

System pressure drop is usually gradual, with the disk falling slowly at first. As the disk falls to about 50% of the full-open position in response to system pressure drop, the reactive forces holding the valve open are partly cancelled. Finally, the total lifting force becomes less than the spring force, and the disk closes sharply from about 50% of its rated lift.

The nozzle ring adjusts the lifting area of the disk and is used to adjust the popping point (lifting pressure) of the valve. Blowdown is adjusted by the adjusting ring. The adjusting ring alters the change in lifting area on the disk as the disk begins to reseat. This means that the spring tension overcomes steam pressure at a different time, thereby changing the blowdown.

10.4.6.1.3 Huddling Chamber Safety Valve

In the huddling chamber safety valve (see Figure 10-16) the static pressure acting on the feather causes initial opening. As the valve pops open, the space within the huddling chamber (between the seat and adjusting ring) fills with steam and builds up more pressure on the outer lips of the feather. The increased area of the feather lips increases the upward thrust against the spring and causes the feather to lift to full opening. After a predetermined pressure drop (blowdown), the valve starts closing, resulting in a reduction in the area of the feather exposed to the steam pressure. This causes the force exerted against the spring to reduce, causing the feather to close.

Blowdown is adjusted by raising or lowering the adjusting ring. Raising this ring decreases blowdown; lowering increases blowdown. Raising and lowering the adjusting ring changes the volume under the disk, which changes the blowdown.

10.4.6.2 Relief Valves

Relief valves (see Figure 10-17) are designed to limit pressure in liquid systems. Relief valves do not pop open, and they do not have a blowdown. Relief valves open in proportion to the pressure applied to them. They are suitable for incompressible liquid systems such as water and oil because for a small amount of liquid released, a large drop in pressure occurs. A relief valve consists of a valve body, stem, disk, seat, spring, adjusting screws, locknuts, inlet, and outlet.

As static pressure overcomes the spring pressure setpoint, the disk lifts off its seat and allows the fluid to escape. When system pressure falls below spring pressure, the valve shuts. Spring tension is adjusted by the adjusting screws and is locked into place using locknuts.

The main disadvantage of the relief valve is chatter. Because relief valves essentially have no blowdown feature, as soon as the system pressure

is below the relief set point, the valve closes. This causes a surge in system pressure that sometimes causes the valve to open again momentarily. This action decreases the life of the valve because excessive opening and closing can damage the seating surface.

A safety valve opens quickly at set pressure for immediate full-flow discharge. In comparison, a relief valve opens and closes slowly, allowing full flow only after significant overpressure builds up in the system.

External operating levers can be installed with safety or relief valves; such levers are required wherever frequent testing is a must. Both relief valves and safety valves are commonly installed on high pressure systems. Typically, the relief valves have a lower actuating pressure than the safety valves. As pressure in the system builds up, the relief valves will open first in an attempt to control the overpressure event. If pressure continues to increase, the safety valves will open to prevent pressure in excess of design values. In most designs of this nature, the relief valves have isolation valves which may be shut if the relief valve sticks open or leaks. Safety valves, on the other hand, are *never* provided with isolation valves.

Both relief valves and safety valves are attached to the system via flanged connections so they can be removed for bench testing. External gagging devices may be used to allow system hydrotesting. Gagging devices are usually threaded stems that impinge on the internal valve stem to prevent its movement.

10.4.7 Specialty Valves

Steam plants need valves for special applications. This section discusses the construction and use of the following specialty valves:

- solenoid valves,
- plug and ball valves,
- diaphragm valves,
- control valves, and

- three-way valves.

10.4.7.1 Solenoid Valves

A solenoid valve (see Figure 10-18) has two major working parts: (1) a solenoid (electromagnet) with a metal core or plunger and (2) a valve containing an orifice with a disk or plug to stop or allow flow. Solenoid valves may be direct acting or pilot operated.

The direct-acting valve is opened or closed by movement of the plunger. When the solenoid is energized (usually by a switch in the control room), electromagnetism draws the plunger into the solenoid. The plunger is attached to or moves the stem or actuator inside the valve to open or close the valve to system flow.

Direct-acting solenoid valves are fully automatic. The solenoid core is mechanically connected to the valve disk and directly opens or closes the valve when energized or deenergized. Valve operation does not depend on line pressure or rate of flow; the valve will operate throughout the full range of rated temperature, pressure, and flow conditions.

The pilot-operated solenoid valve has a pilot orifice and a bleed orifice. Pilot-operated solenoids use line pressure or another fluid (such as compressed air) to operate the main valve. When the solenoid is energized, the pilot orifice opens, allowing a small amount of flow to decrease pressure on top of the valve diaphragm. With pressure decreased on top of the diaphragm, system pressure on the underside (inlet) raises the diaphragm and opens the valve. When the solenoid is deenergized, the pilot orifice closes. Full inlet line pressure is then applied to the top of the piston or diaphragm to close the valve.

10.4.7.2 Plug and Ball Valves

The plug valve's main application is in the handling of fluid/solid mixtures. The main advantage of the plug valve is that foreign material that

might prevent full closure of a gate valve is scraped off the plug as the plug valve closes. Plug valves go from fully open to fully closed with a 90° turn of the handle. In recent years, plug valves also have been used in clear liquid systems where space is limited.

Plug valves (see Figure 10-19) can be cylindrical or tapered and lubricated or non-lubricated, depending on service and frequency of operation. A lubricated tapered plug seats tightly, but if it is operated without lubrication, the plug can jam in the tapered seat and become gouged and scratched. Lubricated plug valves are usually provided with a separate lubricating system that works as the valve is opened or closed. Grease is forced around the plug as well as beneath it, raising it slightly, lubricating it, and permitting easy operation.

Cylindrical and tapered plug valves can also be supported by an inert, resilient liner. In this case, there is no need to lubricate the valve before operation to prevent plug scratching; the resilient liner serves this purpose.

Multiport plug valves may be positioned to permit flow in any of several directions, routing flow through several systems. Usually the incoming flow is directed to the bottom of the plug (the internal opening), and then turns 90° through the port.

The ball valve (see Figure 10-20) is an adaptation of the plug valve. The chief difference is the shape of the valve internals. The plug valve is cylindrical or conical; the ball valve is spherical. Each has a drilled passage. The ball valve has a round passage, nearly matching the inside diameter of the pipe, while the plug valve has a rectangular-shaped passage. As in plug valves, ball valves go fully open to fully closed with a 90° turn of the handle. The handle always indicates the direction of the drilled passage.

The disadvantages of plug and ball valves are:

- Rapid wear of plug or ball-to-body seals,

- Poor flow regulation, and
- Expense.

An important difference between these valves is that the plug valve restricts flow much more than the ball valve.

10.4.7.3 Diaphragm Valves

Diaphragm valves (see Figure 10-21) have several advantages: they provide smooth fluid passage without pockets, good flow control, and leaktight closure. Diaphragm valves work well even when suspended solids are in the pipeline. Because the working parts are isolated from the fluid, corrosion of the operating mechanism is prevented. Diaphragm valves are suitable for lines handling corrosive fluids, fibrous slurries, sludges, solids in suspension, water, gases, and compressed air. They are used extensively in radioactive fluid systems, where their leaktightness is a major asset.

Diaphragm-type valves belong to the general class known as "packless" valves because the flexible diaphragm between the body and the bonnet eliminates the need for a stuffing box to prevent leakage around the stem. The diaphragm, which is made of a flexible elastomer, seals the operating mechanism from the fluid passing through the body so the operating mechanism of a diaphragm valve is never in contact with corrosive chemicals or other pipeline materials.

The valve diaphragm is the only part that wears significantly. It can be replaced without removing the valve body from the pipeline. Several valve parts eliminated in the diaphragm valve include the packing glands, disk holder, and seats.

Two types of diaphragm valves are the weir and the straightway. The weir diaphragm valve has a flexible diaphragm connected to a compressor plug. The compressor plug is connected to a stud molded into the diaphragm. The compressor plug is moved up or down by the valve stem. The diaphragm is lifted high when the compressor is

raised (valve open) and is pressed tightly against the valve body weir when the compressor is lowered (valve closed). The weir is a type of valve seat.

The straightway diaphragm valve is similar to the weir valve except it does not have a weir-type seat. When the valve is open, fluid flows straight through, not up and over the valve seat. The diaphragm lifts high for full, streamlined flow in either direction. When the valve is closed, the diaphragm seals tightly for positive closure even with gritty or fibrous materials in the line.

For corrosive fluid applications, diaphragm valves are made of stainless steel or polyvinyl-chloride (PVC) plastics. Diaphragm valves also may be lined with glass, rubber, lead, plastics, titanium, or other materials. The life of the diaphragm depends on the nature of the fluid handled, its temperature and pressure, and the frequency of valve operation.

10.4.7.4 Control Valves

Control valves are the basic regulatory device in any process using fluid streams. Therefore, operators must be thoroughly familiar with the different types of these valves and their flow characteristics.

A control valve consists of two major subassemblies—a valve body and an actuator. The valve body subassembly is the portion that actually controls the passing fluid. It consists of a housing, internal trim, bonnet, and sometimes a bottom flange. The valve body is a pressure-carrying part (a pressure vessel) that must meet all the applicable pressure, temperature, and corrosion requirements in the same manner as a normal pressure vessel. The actuator sits on the valve body and positions the valve stem and disk, depending on control signals received.

The most common control valve body style is the globe valve. Such a control valve body can be either single- or double-seated.

In an air-operated control valve (see Figure 10-22), control air pushing on the diaphragm provides operating power for the valve. The valve in Figure 10-22 has a direct-spring action to open the valve while control air pushes the diaphragm and stem down to close the valve. An increase in control air pressure above the initial spring setting forces the stem down against the spring compression. The resulting valve action is known as air-to-close (or fail open) action. The actuator may also be made with a reverse-spring return, where air pushes up under the diaphragm, resulting in an air-to-open (fail close) action.

A stop in the valve's upper case holds the initial diaphragm position. The spring is normally set so the stem starts to move when air pressure to the diaphragm is equal to the minimum spring range. Spring compression can be changed with an external adjusting screw.

The best orientation for any control valve is upright. Most piping specifications call for control valves to be located above grade or platform elevation and at the edge of accessways. For in-place maintenance, clearance space is required below and above the valve to remove the seat, plug, actuator cover, spring, and yoke.

10.4.7.4.1 Single-Seated Valves

Single-seated control valves (see Figure 10-22) are usually used (1) when positive shut-off is required, (2) when piping sizes are 1 inch and smaller, and (3) where the actuator is not affected by unbalanced forces acting on the disk. On single-seated control valves, the pressure on one side of the valve disk is always greater than on the other side.

10.4.7.4.2 Double-Seated Valves

A double-seated control valve (see Figure 10-23) is designed so that the pressures on the inlet side of the two seats counter each other. The advantage of double-seated construction is that it reduces the actuator forces required to move the

valve. The hydrostatic effects of the fluid pressure acting on the two disks tend to cancel out. Because double-seated valves have upper and lower disks of different diameters to allow removal of the smaller lower disk through the upper port, the pressure forces are not completely balanced.

10.4.7.5 Pressure-Reducing Valves

A pressure-reducing valve is a control valve used for controlling the downstream pressure or flow rate of a fluid from a high pressure source. Three general types are (1) self-contained internal pilot piston-operated, (2) self-contained external pilot-operated, and (3) spring- or weight-loaded, direct-operated with a diaphragm, bellows, or piston. A self-contained or self-operated valve uses the fluid being controlled to operate its main valve.

The operation of a self-contained pressure reducing valve (see Figure 10-24) is the same whether it is internally or externally controlled. High pressure fluid enters the valve on the inlet side and acts against the main valve disk, tending to close the main valve. However, the high pressure fluid is also ported to the top of the main valve piston, which has a larger surface area than the main valve disk, tending to open the main valve.

An auxiliary valve is used to control the amount of pressure acting on the top of the main valve piston. The auxiliary valve is positioned by a controlling diaphragm that senses the downstream (reduced) pressure. The position of the diaphragm at any given moment is determined by the relative strength of two opposing forces: (1) the downward force exerted by the adjusting spring, and (2) the upward force exerted on the underside of the diaphragm by the reduced pressure fluid. These two forces are continually seeking to reach a state of balance; because of this, the downstream (reduced) pressure is kept constant as long as the amount of fluid used downstream is kept within the capacity of the reducing valve.

Pressure-reducing valves can accommodate a wide range of capacities and pressure differen-

tials. Pressure control over an extremely wide capacity range might require two control valves in parallel, one for the high flow rates and the other for the low flow rates.

With high pressure or a large pressure differential, a pressure-reducing valve should not operate close to its seat. The resulting high velocities can wear the plug and seat, causing inaccurate pressure control and leakage when the valve shuts.

10.4.7.6 Three-Way Valves

A three-way valve is an extension of the globe valve that can be used for diverting or combining (mixing) service. A three-way valve has a three-ported body containing two valve seats. The stem positions the plug against the upper seat, lower seat, or some point in between.

Figure 10-25 shows a three-way valve connected for diverting service. In this application the fluid entering the inlet port is diverted so that flow can exit through outlet port A or B, or both outlet ports. An upward movement of the plug decreases the flow exiting through outlet port A and increases the flow exiting through outlet port B.

Figure 10-26 shows a three-way valve used for combining service. In this application the fluid entering inlet port A and the fluid entering inlet port B are combined and exit through outlet port C. A downward movement of the plug decreases the flow passing through inlet port A and increases the flow passing through inlet port B.

10.4.7.7 Deluge Valves

A deluge valve (see Figure 10-27) can be manually or automatically opened to let a high flow rate of fire protection water douse the affected area. When thermal detectors monitor the protected area, a sudden rise in ambient temperature can cause the valve to open.

Figure 10-27A shows a cross section of a deluge valve in the closed position. Automatic

actuation of a fire sensor (or manual initiation) energizes (opens) the solenoid valve. The solenoid valve vents off the water that, with the spring, held the clapper closed. Fire water system pressure compresses the spring to open the clapper. Water flows over the lip of the inlet line and out the discharge line to the sprinkler(s) served.

10.4.8 Valve Packing

Valve packing (see Figures 10-6 and 10-10) is the malleable, replaceable material used within the stuffing box of a valve bonnet to prevent leakage around the valve stem. The stuffing box is the recessed area surrounding the stem where the stem enters the valve bonnet. Valve packing arrangements include an adjustable slide feature (packing gland and/or follower) to allow for compressing and tightening the packing. Packing material must be malleable to be form-fitting, but must cause little friction with stem rotation or movement. The packing must stop the fluid from leaking out, while allowing the stem to move.

The conventional way to load the packing is to tighten the packing gland nuts. A more recent innovation is the live-loaded packing system that places Belleville springs (washers) between the packing follower and the packing. The packing load is then determined by the spring constant and the amount of compression of the Belleville springs.

Teflon is often used for packing valves. Teflon has excellent chemical inertness and good lubricating properties. Teflon can be used in solid-molded or turned form (chevron rings), or it can be used as a lubricant for asbestos packing. Disadvantages of solid Teflon packing are its high coefficient of thermal expansion, particularly near room temperature, and the need for extra-fine surface finishes. Surface finishes of 8 rms (roughness in micro-inches) on the stem surface and 16 rms at the inside of the packing box are commonly specified to prevent undue friction and wear of the Teflon rings. Teflon can also be cut and used as split rings. Although Teflon is an excellent packing material for low temperature

water applications, it breaks down at elevated temperatures (beginning between 450° and 750°F, depending on the application).

Braided asbestos is also a common packing material because it can be made in split rings that can be wrapped around the valve stem. This type of packing usually uses additives such as mica or graphite for lubrication, particularly in high temperature service. The maximum temperature limit of asbestos is approximately 1000°F.

Teflon used as a lubricant for asbestos packing is either a suspensoid or a pure braided covering around an asbestos core. A pure braided Teflon cover around asbestos is preferred because it combines the elasticity and deformability of asbestos with the smoothness of Teflon.

A recent addition to the list of available packing materials is carbon ribbon. Carbon ribbon is a flexible all-graphite product with direction-dependent properties similar to pyrolytic graphite. It is essentially chemically inert, except when strong oxidizers are handled. The coefficient of friction is low and the packing can be used for the high temperatures a power plant produces. Care must be taken in adjusting this packing; it has a high density, and overtightening could lead to a lock-up of the valve stem. A disadvantage of carbon ribbon is that the surface roughness limits are comparable to those of Teflon.

"O" rings or chevron rings are made of elastomers such as Neoprene or Buna-Y. They can be used for certain low pressure valves handling nonabrasive fluids below 180°F. This type of packing material is found in certain specialized valve applications, such as temperature control valves for air-conditioning units.

10.4.9 Gaskets

Gaskets are the replaceable materials used to seal flat surface junctions (see Figure 10-6). For common valves rated at 300 psi and below, rubber-bonded asbestos gaskets, approximately 1/16-

inch thick, can be used as bonnet and flange gaskets. For higher pressures and temperatures above 250°F, metal-clad asbestos gaskets are used.

The most common gasket used in the power plant is called a "flex." A flex is a spiral wound system of stainless steel and asbestos or Teflon. A thin strip of asbestos and stainless steel is coiled like a rope on a flat surface. The flat disk-like gaskets can then be crushed between two flanges or a valve bonnet and body. These gaskets have brand names such as Spirotallic or Flexitallic. Spiral-type gaskets with Teflon filler are limited to about 450°F; those with asbestos are used up to 1000°F.

10.5 Valve Operators

Valve operators (also called valve actuators or positioners) move the valve stem, and thus the disk, in and out of the valve seating area. The following valve operators are discussed in this section:

- manual operators,
- electric operators,
- pneumatic operators, and
- hydraulic operators.

10.5.1 Manual Operators

Manual operators can adjust a valve to any position. Typical manual operators are the handwheel operator, the handheld air motor, and the chain operator.

Handwheels are directly attached to the valve stem. The size (diameter) of the valve wheel provides the only mechanical advantage (leverage) to operate the valve. When large manual valves are exposed to service conditions that make operation difficult because of binding (high temperature or high system pressure), a "pounding-" or "hammer-" type handwheel may be provided. The "hammer" moves freely through a portion of handwheel travel, then hits against a lug on a secondary wheel.

The secondary wheel is attached to the valve stem. With this type of operator, the valve can be pounded shut for tight closure, or pounded open if stuck shut.

If additional mechanical advantage is needed, the valve bonnet can be fitted with gears. In such cases, a special wrench (handheld, air or motor driven) is provided. A plant equipment operator attaches the portable air or electric motor to a lug on the valve and drives the valve open or closed through the gear arrangement. This allows one operator to operate the valve when, because of the gear ratio, such operation would normally take a long time and/or another operator's assistance. When a valve's location does not permit easy access to the handwheel, chain wheels can be fitted to the valve stem. The chain may be allowed to hang free from the handwheel or can be held out of the normal traffic pattern. The operator works the chain wheel to move the valve wheel (counterclockwise to open, clockwise to shut), just as if the operator were grasping the valve handwheel itself.

10.5.2 Electric Operators

Electric motors are fitted to valves throughout the plant. The advantages of motor-operated valves over manual valves include:

- remote operation, usually from the control room,
- rapid opening and closing, and
- automatic operation on a signal from another component (e.g., a tank level switch).

Attaching an electric motor operator (see Figure 10-28) usually makes the valve beneath it unrecognizable because of the size and complexity of motor operators. Electric motor operators have a control and switching box, a drive motor, a handwheel for manual operation, an operating shaft, and a gear box. Position limit switches, torque limit switches, or a combination are used. The limit switches monitor the valve opening/

closing and indicate valve position (usually by red and green lights) in the control room.

Of major concern to plant operators is manual operation of a motor-operated valve. After just a few open-close cycles from the control room, operators become accustomed to the time it takes a valve to achieve its full stroke (typical stroke time is 12 inches per minute). When the same valve must be operated by hand, however, operators will find they must turn the handwheel for some time to fully open or close the valve. (Note that the engage-disengage lever must be moved to the manual position.) It takes longer to position a motor-operated valve manually because of the gearing used between the motor and valve stem. In an automobile, high engine speed coupled to a transmission in first or second gear gives high torque to the rear wheels but at a low wheel speed. Valve operators use the same principle: high motor speed coupled through a high ratio gear box increases torque.

10.5.2.1 Limitorque Valve Operators

The Limitorque type of electric valve operator (see Figure 10-29) controls and limits the opening and closing travel of the valve. Proper valve seating is very important because the valves can be damaged by overtightening the valve in either the closed or open (backseat) position. By limiting torque and thrust loads with the valve torque limit switches, the valve closing or backseat torque can be closely controlled.

The Limitorque design provides a constant-seating thrust, ensuring that a valve is fully seated on each stroking operation and automatically compensates for valve seat and disk wear. This seating thrust can be varied by means of a micrometer adjustment of the torque limit switches.

The torque limit switch becomes operative and disconnects the drive motor if an obstruction is met, regardless of whether valve travel is complete. This prevents damage to the valve seat, disk, and stem. The torque limit switch also serves as a

backup to the valve travel limit switch and keeps the valve from being jammed in the open or closed position if the travel limit switch malfunctions.

Gear-driven limit switches govern valve travel in the open or closed direction. These switches also regulate the position indicator lights when provided. The geared limit switches are of the rotary-drive type. Depending on the type of operator, both the geared limit switches and the torque limit switches are always "in-step" during both motor and hand operation. Keep in mind, however, that electrical interlocks are of little use during manual operation.

The size of the Limitorque operator used depends on the size of the valve and its application. The differential pressure across the valve, stem diameter, desired opening and closing times, operating voltage, fluid temperature and frequency of service are all considered when matching an operator to a valve. Limitorque operators used in nuclear service typically have an SMB designation. There are currently eight sizes available, ranging from SMB-000 (smallest) to SMB-5 (largest). The discussion which follows is for a SMB-0 operator, but is also applicable to SMB-1, 2, 3, and 4 operators.

10.5.2.1.1 Description of Motor Operation

The motors used on the Limitorque valve controls are high-starting torque, totally enclosed motors. They are furnished in weatherproof, explosion-proof, or submersible enclosures. All motors are furnished with ball bearings and provided with grease seals. No lubrication of these motors is necessary because they are lubricated at the factory for lifetime operation. All 3-phase AC motors are of the squirrel cage design, and DC motors are compound wound. The motor (see Figure 10-30) transforms the electrical energy input to mechanical energy output. This mechanical output energy is transmitted through a series of gears inside the main housing to open and close the valve.

A reversing starter and overload relay must be wired in series with the input motor leads to control motor directional rotation and limit motor current, respectively. These two components may be enclosed in the limit switch compartment or wired to the unit from a central motor control station.

As shown on Figure 10-30, the electric motor (14) has a helical pinion mounted on its shaft extension. This pinion (13) drives the worm shaft clutch gear (12) which is engaged with the worm shaft clutch (11).

The worm shaft clutch is splined to the worm shaft (6). A spring (10) pushes the clutch along the splines on the worm shaft and engages the clutch with the worm shaft clutch gear.

Two lugs cast into the top portion of the worm gear (17) engage the two lugs on the drive sleeve (19).

The lugs are spaced so that when the worm gear begins to turn during motor operation, there is a certain amount of lost motion before the lugs engage and cause the hammer blow effect within the operator. This hammer blow effect will help to unseat valves stuck on a backseat or seat.

As soon as the worm gear lugs engage, the drive sleeve (being splined internally with the stem nut (20) causes the stem nut to rotate and open or close the threaded stem of the valve.

The stem nut is threaded internally to fit the thread of the particular valve. In the case of nonrising stem valves, or where the electric motor is mounted in tandem with an additional gear drive, the stem nut is merely bored and keyed to fit the shaft.

The thrust developed by a Limitorque operator is absorbed by the thrust bearings (16) and (18) on the top and bottom of the main drive sleeve.

As the operator develops greater torque when

seating a valve, encountering an obstruction, or during a valve malfunction, the worm (21) slides axially along the splines of the worm shaft and compresses the belleville springs in the spring pack (located within the torque limit sleeve) (3). The spring pack worm assembly has a rack machined onto the bearing cartridge (4) which engages with the gear located on the shaft of the torque switch (2).

When the worm moves axially as a result of increased load on the gearing, it rotates the shaft of the torque switch. When the torque switch reaches a preset torque value, it opens a pair of electric contacts, which are wired into the motor control circuit. These contacts interrupt the circuit and stop motor operation.

A simplified representation of the operation of the worm is shown in Figure 10-31. During normal valve movement, the worm assumes an equilibrium position on the splined worm shaft and simply rotates in place, turning the worm gear. When the valve disc/stem encounters increased movement resistance due to contacting the valve seat or an obstruction, the increased resistance creates increased back torque that is transmitted through the stem nut and drive sleeve to the worm gear. The increased back torque tends to slow or stop the rotation of the worm gear. However, the motor and the associated gearing are continuing to turn the worm shaft and worm at the original speed. The speed difference resulting from the increased back torque causes the worm to "dig" into the worm gear teeth and move axially (to the right in Figure 10-31) along the splined worm shaft. If the back torque is sufficient, the worm will compress the Belleville spring pack enough to operate the torque switch, which stops current flow to the motor. (For schematic simplicity, the torque switch shown in Figure 10-31 is different from the switches found on most Limitorque valves, but the action is the same.) The ability of the worm to either rotate in place normally or move axially along the splined worm shaft when increased back torque is encountered is the heart of the torque-limiting action of a Limitorque motor operator.

This feature of the operator keeps the valve from being damaged in the event of excessive torque, i.e., valve malfunction or an obstruction to valve operation. It also enables the valve to develop a predetermined amount of torque to seat globe and gate valves and obtain a leaktight seal.

The spring pack is simply a series of Belleville springs which are initially compressed a certain amount by the stop nut on the end of the assembly. The amount of initial compression or preload on the springs determines the amount of worm travel when torque loads increase. This in turn determines the amount of torque applied by the operator for a given torque setting on the torque switch.

The torque switch has two sets of contacts (open, close) which are actuated mechanically by the rotation of a pinion on the shaft, which engages with a worm on the spring pack assembly. A dial on the front of the torque switch can be set for a desired torque output of the operator. The greater the torque setting, the more the cam must rotate to open the contact (equivalent to a longer worm travel and a higher torque output).

The geared limit switch (1) is directly geared to the worm shaft and is in step at all times with the movement of the operator. Once the geared limit switch is set to trip at its proper position of valve travel, it will trip at the same point every time.

Generally, the torque switch is wired into the motor control circuit to stop the operator in the closed position on torque-seated valves, and the limit switch is wired into the control circuit to stop the operator at the full-open position. However, even on torque-seated valves, the limit switch must be set to trip at the closed position, once the torque switch has tripped, to open contacts for "open" light indication.

The 8-contact geared limit switch employs two rotary drum switches, each having four contacts. Important uses of these limit switches are to provide valve position indication and valve stroke control. When the rotor is properly set to trip at the

desired position, two of these contacts open electric circuits and two contacts close electric circuits. Generally, one rotor is set to trip at the full-open position and the other is set to trip at the full-closed position of the valve. Each drum switch may be adjusted independently of the other.

10.5.2.1.2 Description of Hand Operation

In the event of a power failure, a handwheel is provided for emergency hand operation of the Limitorque valve actuator. The SMB type of operator has an automatic handwheel declutching arrangement. In order to hand operate the type SMB operator, the declutch lever is pulled downward. This mechanically disconnects the electric motor from the valve operator through the clutch assembly.

This declutching action is similar in all the larger size SMB operators. Refer to Figure 10-32 for the SMB-0 operators. When the declutch lever is depressed, the declutch lever shaft causes the clutch trippers to push the worm shaft gearing out of engagement with the motor helical gearing and into engagement with the handwheel pinion gear.

When the handwheel is rotated, the handwheel pinion gear, which is engaged with the worm shaft gearing, turns the worm shaft. The worm rotates the worm gear and puts the operator into motion.

When the electric motor is energized, the tripper pin (which is part of the clutch gearing) causes the clutch trippers to be released, allowing the clutch to be released. A spring located behind the clutch pushes the clutch along the splines on the worm shaft and engages the clutch with the worm shaft clutch gear. Now power is again transmitted through the motor pinion to the worm shaft clutch gear and on through the worm shaft.

When the handwheel is turned it does not rotate the motor. Similarly, when the motor is in operation, the handwheel does not turn. In the SMB-0 and larger operators, the handwheel drives the operator through the same train as the motor

and will operate the torque switch.

10.5.2.1.3 SMB-000 Actuator Differences

The primary differences between the smaller SMB-000 and the larger SMB-0 actuators, from a mechanical standpoint, are in the declutch assembly parts, the handwheel gearing, and the actuation gearing for the torque and limit switches. An SMB-000 actuator is shown in Figures 10-33 and 10-34.

The electric motor, like that on the SMB-0, has a helical pinion mounted on its shaft extension. This pinion drives the worm shaft gear, which is keyed to the worm shaft. The worm shaft is splined to the worm so that rotation of the worm shaft causes rotation of the worm. From this point, power is transmitted to the valve stem through the worm, worm gear, drive sleeve, and stem nut, respectively, just as in the SMB-0.

The torque switch assembly operates in the same manner as that used on the SMB-0, except for the way in which it is actuated. Instead of having a gear that is actuated by the axial movement of the worm against the spring pack assembly, axial movement of the worm moves an arm that mates with a machined recess located behind the teeth of the worm.

The geared limit switch assembly also operates in the same manner as that used on the SMB-0 except that a different type gear drives the limit switch gear. Instead of being driven by a worm machined onto the worm shaft, the geared limit switch is directly geared to a bevel gear on the drive sleeve. Just like the SMB-0 limit switch, it also is in step at all times with the movement of the operator.

Unlike the SMB-0, which has a clutch splined to the worm shaft, the SMB-000 has a clutch ring, which is mounted on the drive sleeve just above the worm gear and is moved upward by the clutch fork assembly (for hand operation). The clutch fork assembly is keyed to the declutch lever shaft.

When the declutch lever is depressed, the clutch ring moves the clutch keys upward until they engage with the lugs on the bottom of the handwheel.

This assembly (clutch ring, clutch key, clutch fork) is held in the upward position by the clutch tripper lever assembly. The operator will remain in hand operation until the electric motor is again energized.

When the motor is energized, cams mounted on the worm shaft automatically cause the trippers to release the clutch ring and clutch keys from their hand position. Rotation of the handwheel during motor operation will have no effect.

Unlike the SMB-0 actuator, which has a slide-mounted handwheel with a gear located on its extension shaft that engages with a clutch pinion gear during hand operation, the SMB-000 has a top-mounted handwheel. The handwheel has two lugs that engage with the clutch keys.

In the SMB-0 and larger operators, the handwheel drives through the same train as the motor and will operate the torque switch; however, in the SMB-000 and SMB-00, the handwheel turns the drive sleeve directly and will not operate the torque switch.

10.5.2.1.4 Limitorque Operator Problem Areas

Nuclear power plant applications have demonstrated several problem areas associated with motor powered Limitorque actuators. These include environmental and seismic qualification, and problems related to higher valve speeds.

At moderate operating speeds, service has been satisfactory. However, the necessity for higher speeds in nuclear operations, particularly in safety systems, has caused problems. Higher speeds have been achieved by simply changing the gearing in existing actuators. Therefore, the momentum of the high speed motor rotor has resulted

in damaged and jammed valves. Valves that are rigid near the seat area (for resistance to leakage from distortion by temperature changes) experience higher loading. The increased loading has damaged disks, seats, stems, and bonnets.

Changing the limit switch settings does not solve the problem; it merely creates other problems. Cutting motor current farther from the seat causes incomplete seating if friction changes.

Changing torque-switch settings helps, but even this will not eliminate two electrical problems: unavoidable time-delay during torque switch and starter-coil trip, and excess thrust when full line voltage is used on motors designed to give required thrust at reduced (degraded) voltages. The degraded voltage requirement is imposed by safety-related equipment design considerations.

Environmental hazards for nuclear plant actuators must be considered when testing operators. Ambient temperature peaks of 340°F, pressure peaks of 70 psig, radiation, and steam and chemical sprays are included in month-long test conditions. Typically, the actuator must operate 20 times during and after the test.

10.5.2.2 Motor Operated Valve Control Circuit

Figures 10-35 and 10-36 illustrate the operation of a typical motor-operated valve (MOV) control circuit. The circuit in Figure 10-35 is for a valve with a seal-in feature, such as a gate valve used for system isolation. Figure 10-36 is a typical control circuit for a valve occasionally used by an operator to throttle flow.

In Figure 10-35, the power supply for the MOV is generally from a 480-volt, 3-phase power supply. The motor control circuit is usually supplied from the same source through a stepdown transformer to 120 volts single phase. A fuse is provided on the secondary leg to protect the circuit in case there is a short or a failure in the control circuit.

Note that there are three sets of contacts labeled OL in series with the opening and closing coils. The OL contacts open if the magnetic overload relays sense excessive current going to the motor. There are also three thermal overloads in the power feed to the motor. These thermal overloads will also open to provide protection against excessive current and motor burnout.

There are two operating coils or relays used in the control circuit, one for forward motion and one for reverse motion or, in this case, "opening" and "closing." The "opening" coil reverses the power leads from the "closing" configuration of phases A, B, and C. When the opening coil is energized, A, B, and C are tied on to T₁, T₂, and T₃, respectively. Conversely, when the "closing" coil is energized, the phase configuration is reversed to connect A, B, and C to T₁, T₃, and T₂, respectively (causing the electromagnetic field applied to the motor to rotate in the reverse direction).

The O and C "b" contacts are electrical interlocks for the opening and closing coils to prevent both coils from being energized at the same time, which would damage the motor and power feeds. When the closing coil is energized, the C "b" contact is opened, making it impossible to energize the opening coil. When the opening coil is energized, the O "b" contact is opened, preventing the closing coil from being energized.

The O and C "a" contacts that are in parallel with the selector switch are the seal-in contacts for the operating coils. When the open or close position is selected (a momentary contact), the respective coil is energized closing the seal-in contact, and holding the circuit energized until a limit switch or torque switch is opened to remove power from the circuit.

The control station usually consists of a spring return-to-neutral switch and two indicating lights. Whenever indicating lights are furnished, a red light usually indicates the full open position of the valve, and a green light indicates the full closed position.

When both lights are energized, the valve is in an intermediate position. Other combinations of pushbuttons, lights, and selector switches may be necessary for specific applications.

Also, it should be noted that in actual plant application there would be parallel control stations, or devices (the engineered safeguards feature (ESF) contact, for instance) that would open or close the valve automatically under certain conditions.

The two-train geared limit switch shown in Figure 10-30 employs two rotary drum switches, each having four contacts. When the rotor reaches the desired position, two of these contacts open electric circuits and two contacts close electric circuits. One rotor is set to trip at the full open position of the valve, and the other rotor is set to trip at the full closed position of the valve. Each drum switch may be adjusted independently of the other.

Normally, one circuit on one drum is used to open the "open" holding circuit of the motor controller, and another circuit of the drum is used to operate the "open" indicating light for the valve.

On the other drum, one circuit is used to control the "closed" indicating light, and another circuit may be used to open the "close" holding circuit of the motor controller.

The open limit switch contact is connected in series with the open switch position and seal-in contact. The open limit switch opens to deenergize the opening coil when the valve reaches the full open position.

The close limit switch contact is connected in series with the close switch position and seal-in contact. The close limit switch opens to deenergize the closing coil when the valve reaches the full closed position.

The torque switches provide a means of interrupting the control circuit of the valve actuator if

a mechanical obstruction should be encountered during the opening or closing cycle. If the resistance to valve movement causes the torque to become excessive, the applicable torque switch will open to interrupt the current flow to the associated operating coil to protect the motor and the valve.

The torque bypass switches that are in parallel with the torque switches can be set up to bypass the torque switches if the valve is fully closed or fully open. At these positions the actuator may need extra torque to bring the valve off the closed seat or the open backseat. Some nuclear plants set up the bypass switches such that the bypasses can be closed by an ESF signal, allowing safety-related valve actuators to use maximum torque to move the valves to required ESF positions for an accident.

Figure 10-35 shows the valve in the closed position with the green closed light lit. To open the valve, the operator places the control switch to open. This energizes the opening coil which closes the O "a" seal-in contact (allowing the operator to release the control switch), closes contacts in the motor power supply to turn the motor in the open direction, and opens the O "b" contact in the closing circuit.

Some plants have the open and close limit switches for the lights set up such that as the valve leaves the close seat, the open limit switch for the red light closes, resulting in both the green and red lights being lighted during valve movement. Other plants set up the light limit switches so that both lights are off when the valve is neither open or closed (intermediate position). When the valve reaches the open position, the control circuit open limit switch contact will open to deenergize the opening coil. The light circuit open limit switch will close to energize the red open light (if it is not already on), and the light circuit close limit switch will open to turn off the green light. With the valve open and the opening coil deenergized, the close limit switch in the closing control circuit will be closed and the O "b" contacts will be closed,

establishing a ready path for closing the valve with the control switch.

In Figure 10-35, note that if the valve is closed, an ESF actuation signal will automatically open the valve and will prevent the operator from closing the valve using the control switch. The valve in Figure 10-36 operates similarly to the one in Figure 10-35, except that without a seal-in feature, valve motion will stop whenever the operator releases the control switch.

10.5.3 Pneumatic Operators

Pneumatic (diaphragm) operators (see Figure 10-37) control valve stem movement by using the energy of compressed air. Pneumatic operators generally control or regulate flow but are also used in simple open/closed applications. Pneumatic operator units generally consist of a sealed casing, diaphragm, spring, and shaft (valve stem or extension). Air can be supplied either above or below the diaphragm, depending on whether the air is to open or close the valve. A solenoid valve controls the air supply. When the operator positions a switch to energize the solenoid, air is admitted to the diaphragm, and the valve opens.

As long as the solenoid is energized (and instrument air is available), the pneumatic valve remains open. When the solenoid is deenergized (or instrument air pressure is lost), air is vented from under the diaphragm and the valve closes. With a different instrument air hookup and solenoid control, the valve can be made to close with air pressure and open when air is lost (or blocked by the solenoid).

Valves of the type first described are called "air to open, fail closed." Valves of the second type, are "air to close, fail open." Piping and instrumentation drawing (P&ID) symbol sheets often illustrate these options.

All automatically controlled valves, whether pressure reducing or not, can fail. They fail when they lose their actuating source. In an air-actuated

valve, air is the actuating source. When air is lost, the valve fails, and it fails in a condition (open or closed) that results in the least damage to equipment and personnel.

10.5.3.1 Electronic to Pneumatic Converters

Electronic to pneumatic (E/P) converters are used in a number of measurement and control applications. Two of these applications are: converting the millivolt output of a thermocouple to a pneumatic signal and converting the voltage output of a tachometer to a pneumatic signal. The most frequent use of the E/P converter, however, is to convert the output of an electronic controller to the pneumatic signal necessary to operate diaphragm actuated control valves.

The conversion of an electronic signal to a pneumatic signal is accomplished using an armature bar and a flapper/nozzle motion detector. These components are found in various arrangements, but the operation is basically the same. The electronic signal causes a motion of the armature bar, which has the flapper attached to it. This movement of the flapper results in a change in the distance between the flapper and nozzle, resulting in a change in the pressure of the pneumatic signal out. In all cases, there is a "feedback" signal to minimize the movement needed to the range necessary to produce a signal output of approximately 3 to 15 psi.

The operation of a simple E/P converter is shown in Figure 10-38. In this converter, an increase in current to the coils moves the armature bar such that the flapper is closer to the nozzle. This action increases the backpressure in the line between the nozzle and the fixed restriction. This higher pressure causes the diaphragm of the air relay to flex downward increasing the opening in the path from the air supply to the air output and decreasing the opening in the path to exhaust. The result of the increase in signal current, therefore, is an increase in air output pressure. The bellows provides feedback to the armature bar to reposition the flapper relative to the nozzle. Without this

bellows, the device would have an infinite gain, for a small input the output would go to maximum. The motion needed by the flapper to create full (15 psi) output is approximately .0005 inches. It is easy to see that even a small input signal current to the coils would move the armature bar and flapper enough to obtain full output air pressure.

The bellows, however, senses the change in output pressure and opposes the motion of the armature bar, thus, reducing the gain to some usable level. Therefore, although a small current input would attempt to move the armature bar a large amount, the counteraction of the bellows reduces that motion to the small amount required to produce a proportional change in the output pressure.

10.5.4 Hydraulic Operators

Hydraulic valve operators (see Figure 10-39) convert fluid pressure into valve motion. Generally, the fluid is water or oil.

A piston is usually used to transfer hydraulic force to valve motion. The piston may be directly attached to the valve stem or work through rams or levers.

Hydraulic valve operators are slightly more complicated than pneumatic operators because air can be harmlessly vented off to allow spring pressure to close (or open) the valve. Hydraulic systems generally conserve the working fluid for reuse. As shown in Figure 10-39, the piping arrangement uses a pump, accumulator, and valves to direct pressurized fluid below the operating cylinder (close valve) or above the operating cylinder (open valve). Note that the fluid on the other side of the cylinder must have an escape (vent) path, or the valve will not move (this is called a "hydraulic lock"). The vented fluid generally is directed to an accumulator for reuse or to the suction side of the hydraulic motor. The accumulator is the ready supply that starts valve motion quickly. The hydraulic motor will complete the valve stroke and recharge the accumulator for the

next operation.

The operator on the left of Figure 10-38 utilizes on/off pump operation, controlled by the cylinder position transducer, to supply oil to drive the piston to equilibrium position. This actuator provides high stiffness and accurate positioning. An array of check valves retains pressure to hold the piston at a setting. Motor-speed control can give a cushioning effect at stroke ends. Thrusts in this type actuator go to 16,500 lb, as seating force. Continuous-duty thrust is 50% of this. Strokes are 24 in. maximum in the larger models and 4 in. in the smallest.

The hydraulic-pump motor runs continuously in the actuator shown on the right of Figure 10-38. This actuator consists of a balance beam, flapper and nozzle, force motor, and feedback loop. Signal current in the force-motor coil moves it and the attached balance beam. The motion shifts a flapper in relation to a nozzle and changes pressure in an amplifier. The amplifier controls high-pressure oil flow to the correct side of the piston. A feedback linkage then restores equilibrium. If pump power fails, the spring in the actuator yoke either opens or closes the valve. It is also possible to set up the actuator such that the valve is locked in its last position on a power failure. The electric motor for the hydraulic pump is small, only 1/6 hp. All components are enclosed in this design, and the only external connections are for motor power and control signals.

Because hydraulic fluids are not compressible, these operators can hold valves in midstroke against high system flow. If the motor is stopped with the valve in mid-position and no vent path is available, a very powerful hydraulic lock is placed on the operator, and the valve will not move.

Chapter 10 DefinitionsBLOWDOWN

- The pressure drop required to reseal a safety valve from a wide open, full flow condition.

CHATTER

- The repeated partial opening and closing of a safety or relief valve.

Table 10-1. Pipe Data

Nominal Pipe Size	Outside Diameter	Identification			Wall Thickness	Inside Diameter
		Steel		Stainless Steel		
Inches	Inches	Iron Pipe Designation	Schedule Number	Schedule Number	Inches	Inches
6	6.625	-	-	10S	0.134	6.357
		STD	40	40S	0.280	6.065
		XS	80	80S	0.432	5.761
		-	120	-	0.562	5.501
		-	160	-	0.719	5.187
		XXS	-	-	0.864	4.897
8	8.625	-	30	-	0.277	8.071
		STD	40	40S	0.322	7.981
		-	60	-	0.406	7.813
		XS	80	80S	0.500	7.625
		-	100	-	0.594	7.437
		-	120	-	0.719	7.187
		-	140	-	0.812	7.001
		XXS	-	-	0.875	6.875
10	10.750	-	160	-	0.906	6.813
		STD	40	40S	0.365	10.020
		XS	60	80S	0.500	9.750
		-	80	-	0.594	9.562
		-	100	-	0.719	9.312
		-	120	-	0.844	9.062
12	12.75	XXS	140	-	1.000	8.75
		STD	-	40S	0.375	12.000
		-	40	-	0.406	11.938
		XS	-	80S	0.500	11.750
		-	60	-	0.562	11.626
		-	80	-	0.688	11.374
		-	100	-	0.844	11.062
		XXS	120	-	1.000	10.750

Table 10-2. Allowable Stress Values for Temperatures 650 to 1150°F

ASTM spec. No.	Grade	Nominal composition	Spec. min tensile	Longitudinal joint efficiency factor	P No.	Max allowable stress value lb/in ² for metal temperatures not exceeding °F		
						750	850	950
PIPE:								
BUTT—WELDED:								
A53 CARBON STEEL								
A72 WROUGHT IRON			45,000	0.60	1	6,750		
LAP—WELDED A72			42,000	0.60	2	6,300		
WROUGHT IRON								
ELECTRIC-FUSION-								
WELDED								
A134 CARBON STEEL								
A245A			48,000		1	8,000		
A245B			52,000		1	9,600		
A245C			55,000		1	10,100		
A283A			45,000		1	8,300		
A283B			50,000		1	9,200		
A283C			55,000		1	10,100		
A283D			60,000		1	10,100		
A			48,000	0.80	1	9,600	8,300	
B			60,000	0.80	1	12,000	9,950	
A139								
A153 CLASS I								
CLASS II			45,000	1.00	1	11,250	9,700	
CLASS I			45,000	0.90	1	10,100	8,700	
CLASS II			50,000	1.00	1	12,500	11,000	
CLASS I			50,000	0.90	1	11,250	9,900	
CLASS II			55,000	1.00	1	13,750	12,050	
CLASS I			55,000	0.90	1	12,400	10,850	
CLASS II			55,000	1.00	1	13,750	12,050	
CLASS I		C-Si	55,000	0.90	1	12,400	10,850	
CLASS II		C-Si	60,000	1.00	1	15,000	12,950	
CLASS I		C-Si	60,000	0.90	1	13,500	11,850	
CLASS II		C-Si	65,000	1.00	1	16,250	13,850	
CLASS I		C-Si	65,000	0.90	1	14,800	12,650	
CLASS II		C-Si	70,000	1.00	1	17,500	14,750	
CLASS I		C-Si	70,000	0.90	1	15,750	13,250	
CLASS II		C-½Mo	65,000	1.00	3	16,250	16,250	14,400
CLASS I		C-½Mo	65,000	0.90	3	14,800	14,800	12,950
CLASS II		C-½Mo	70,000	1.00	3	17,500	17,500	15,000
CLASS I		C-½Mo	70,000	0.90	3	15,750	15,750	13,500
CLASS II		C-½Mo	75,000	1.00	3	18,750	18,750	15,900
CLASS I		C-½Mo	75,000	0.90	3	16,850	16,850	14,300
CLASS II		C-Mn-Si	75,000	1.00	1	18,750	15,650	7,800
CLASS I		½Cr-½Mo	65,000	1.00	3	16,250	16,250	14,400
CLASS II		½Cr-½Mo	65,000	0.90	3	14,800	14,800	12,950
CLASS I		1Cr-½Mo	60,000	1.00	4	15,000	15,000	14,200
CLASS II		1Cr-½Mo	60,000	0.90	4	13,500	13,500	12,800
CLASS I		1½Cr-						
CLASS II		½Mo-Si	60,000	1.00	4	15,000	15,000	14,400
CLASS I		1½Cr-						
CLASS II		½Mo-Si	60,000	0.90	4	13,500	13,500	12,950
CLASS I		2½Cr-1Mo	60,000	1.00	5	15,000	15,000	14,400
CLASS II		2½Cr-1Mo	60,000	0.90	5	13,500	13,500	12,950
CLASS I		5Cr-½Mo	60,000	1.00	5	13,700	13,100	12,400
CLASS II		5Cr-½Mo	60,000	0.90	5	12,300	11,800	11,150
A159								
CLASS I							10,000	
CLASS II							9,000	
CLASS I							11,000	
CLASS II							10,000	
CLASS I							9,000	2,200
CLASS II							8,000	1,950

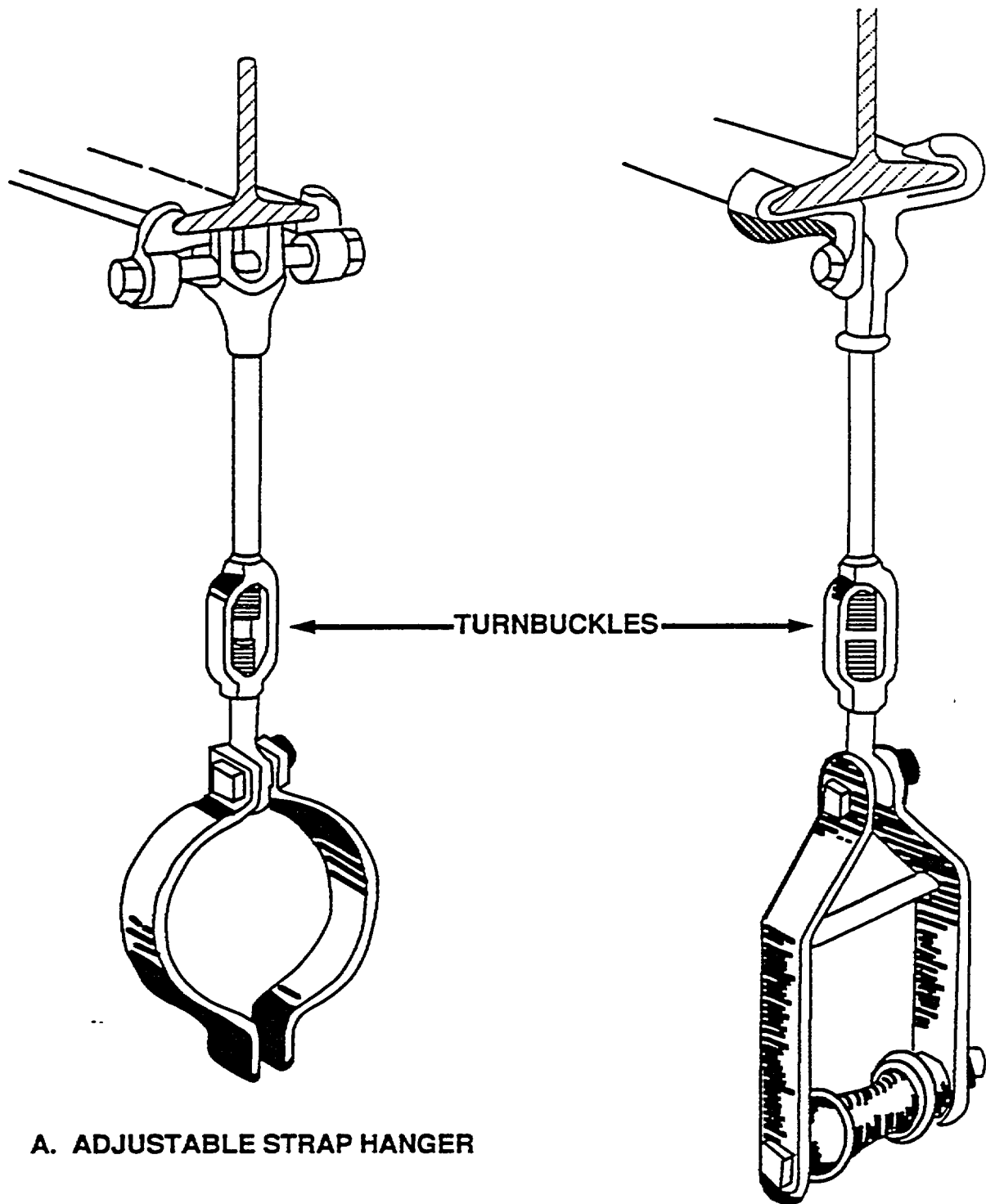


Figure 10-1. Common Adjustable Hangers

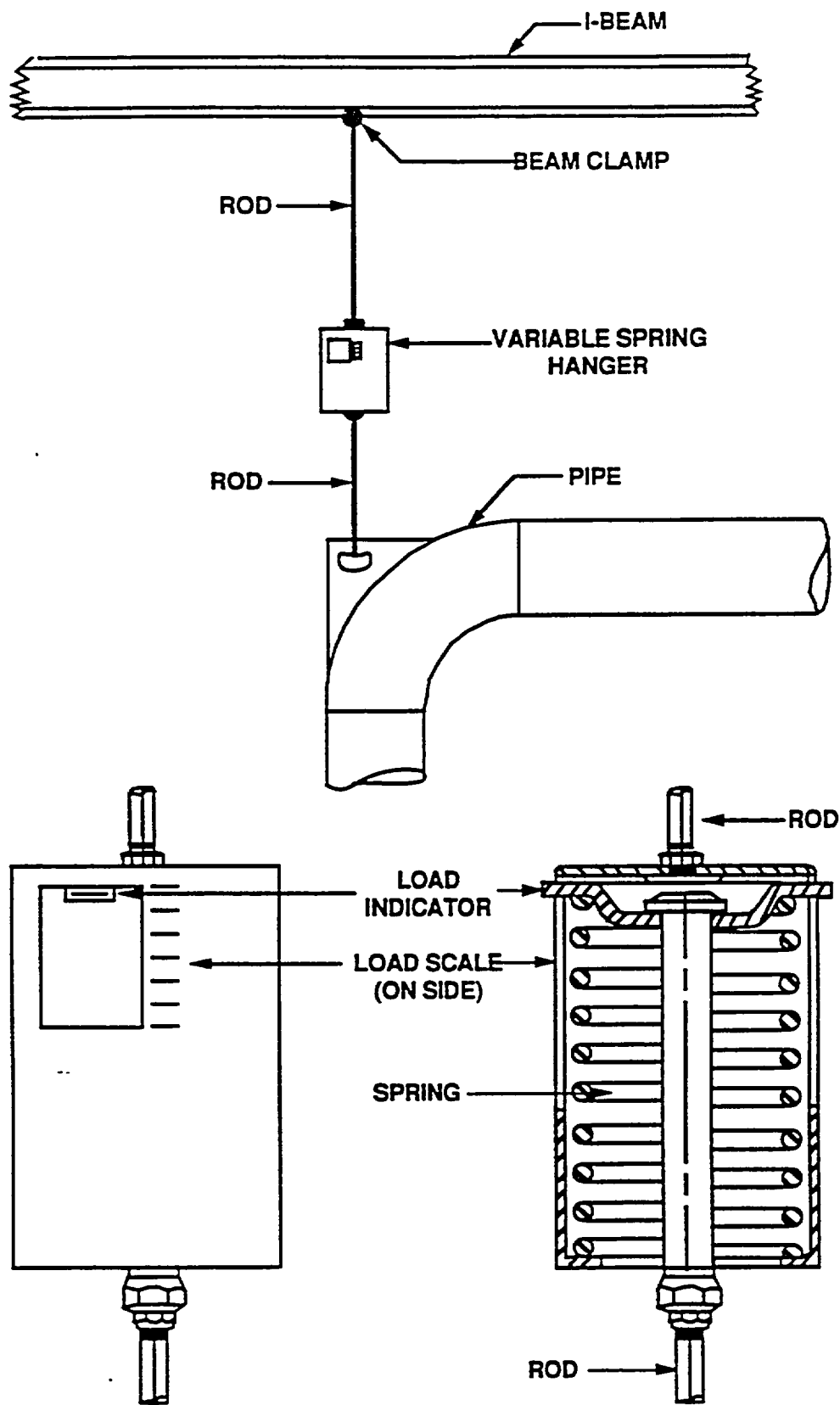


Figure 10-2. Variable Spring Hanger

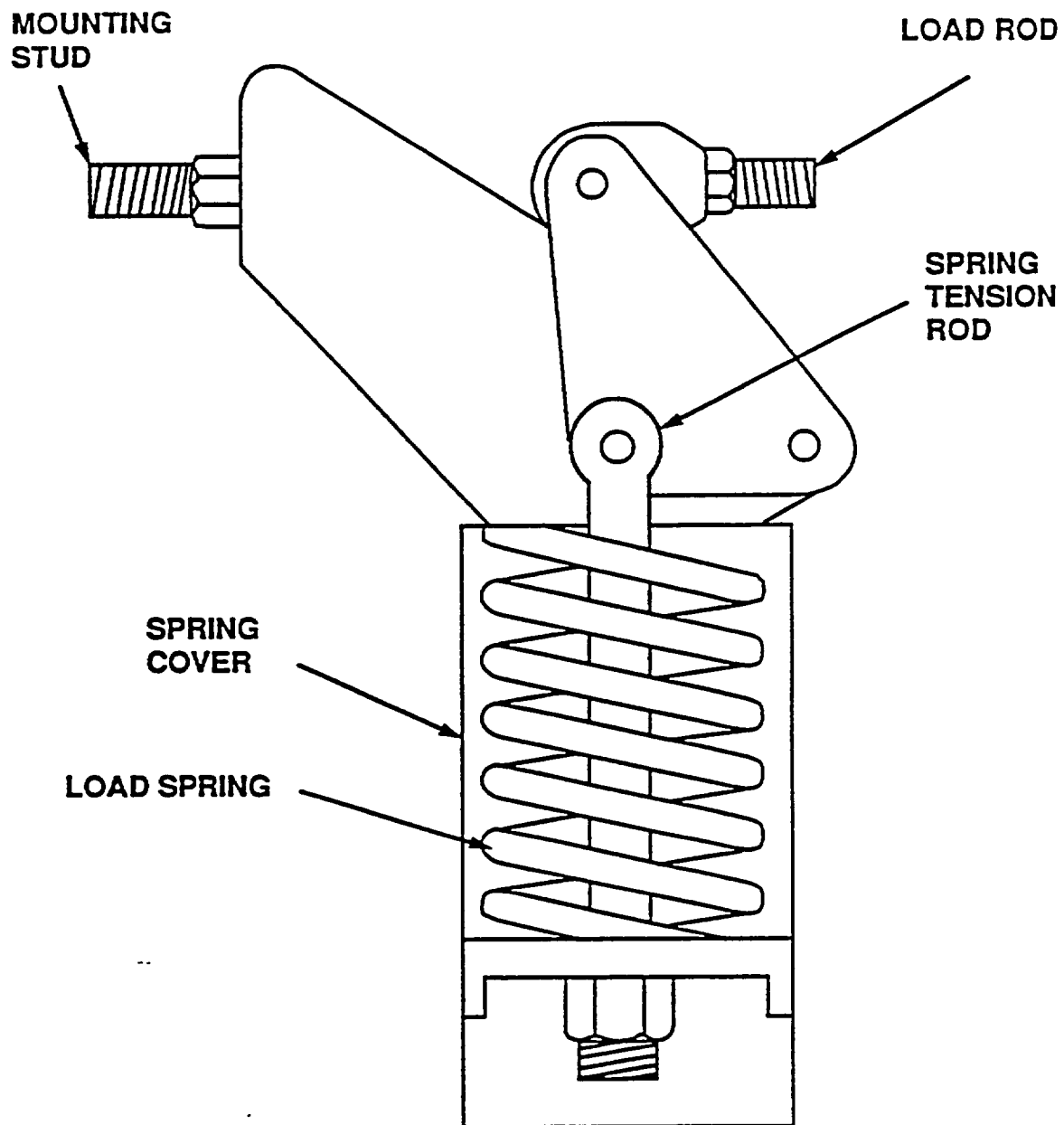
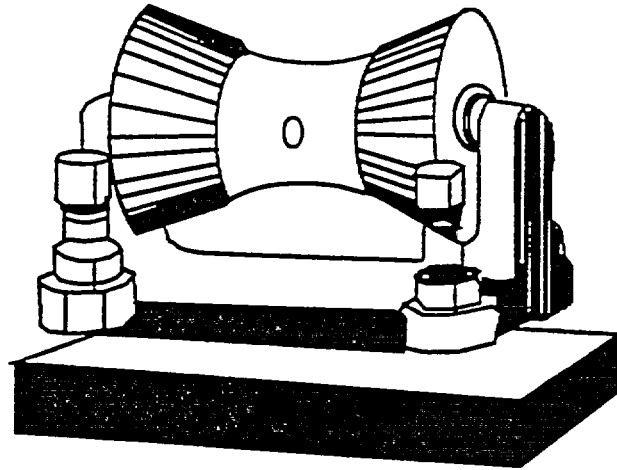
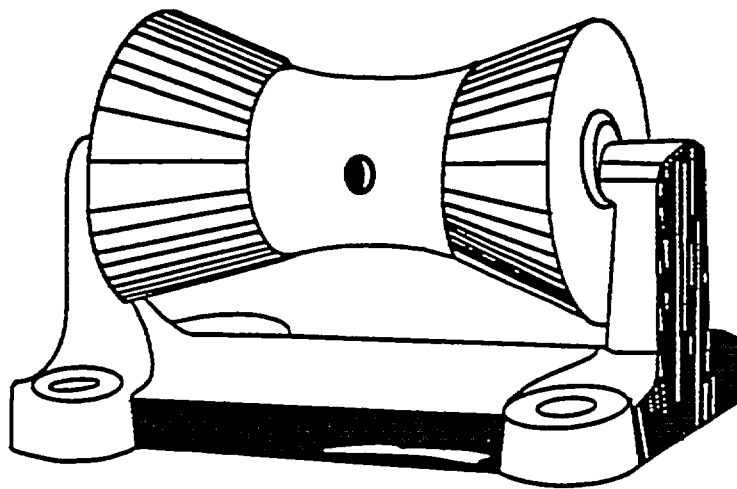


Figure 10-3. Constant Support



A. ADJUSTABLE ROLLER STAND



B. NONADJUSTABLE ROLLER STAND

Figure 10-4. Roller Stands

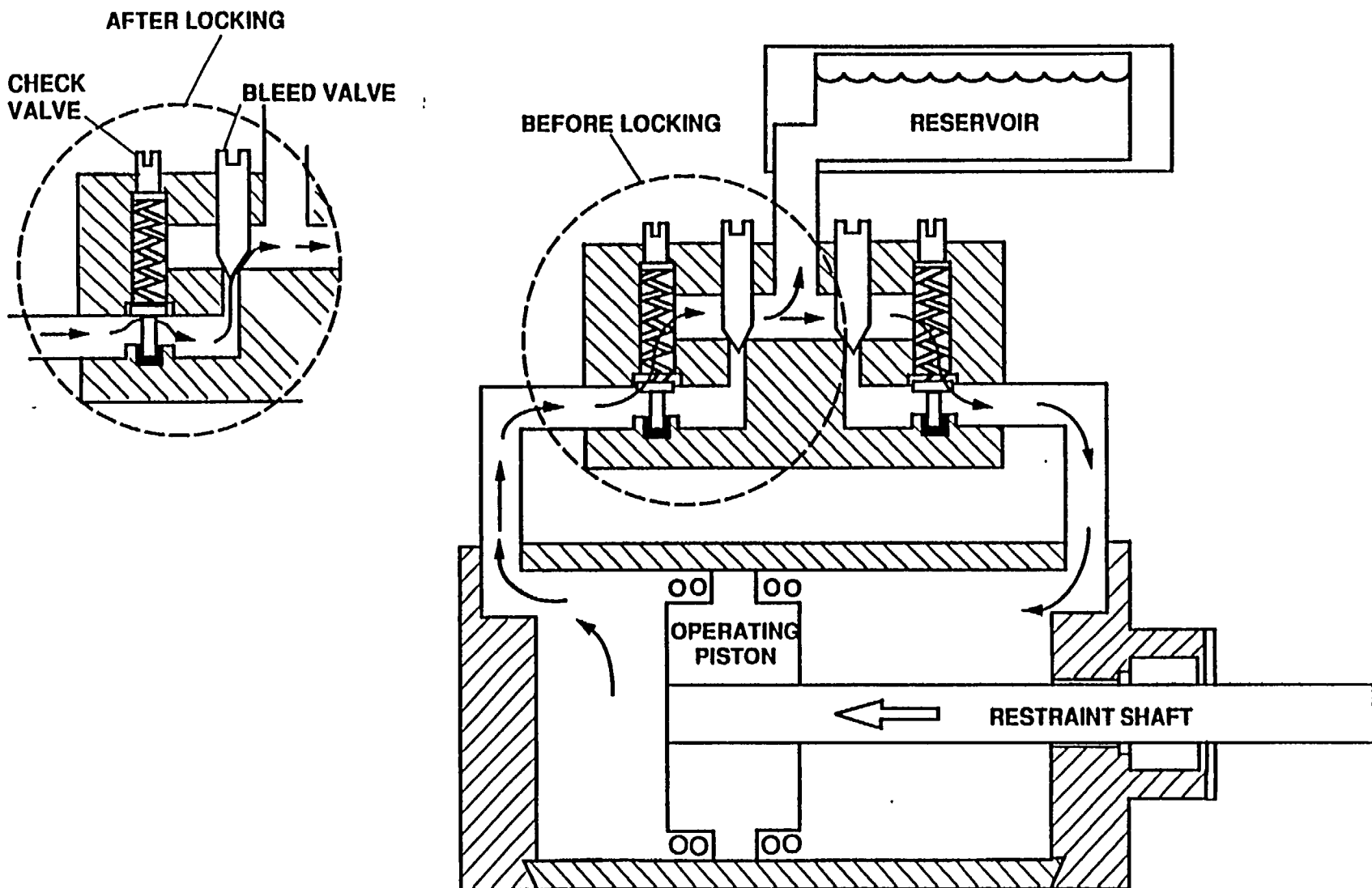


Figure 10-5. Hydraulic Snubber Basic Arrangement

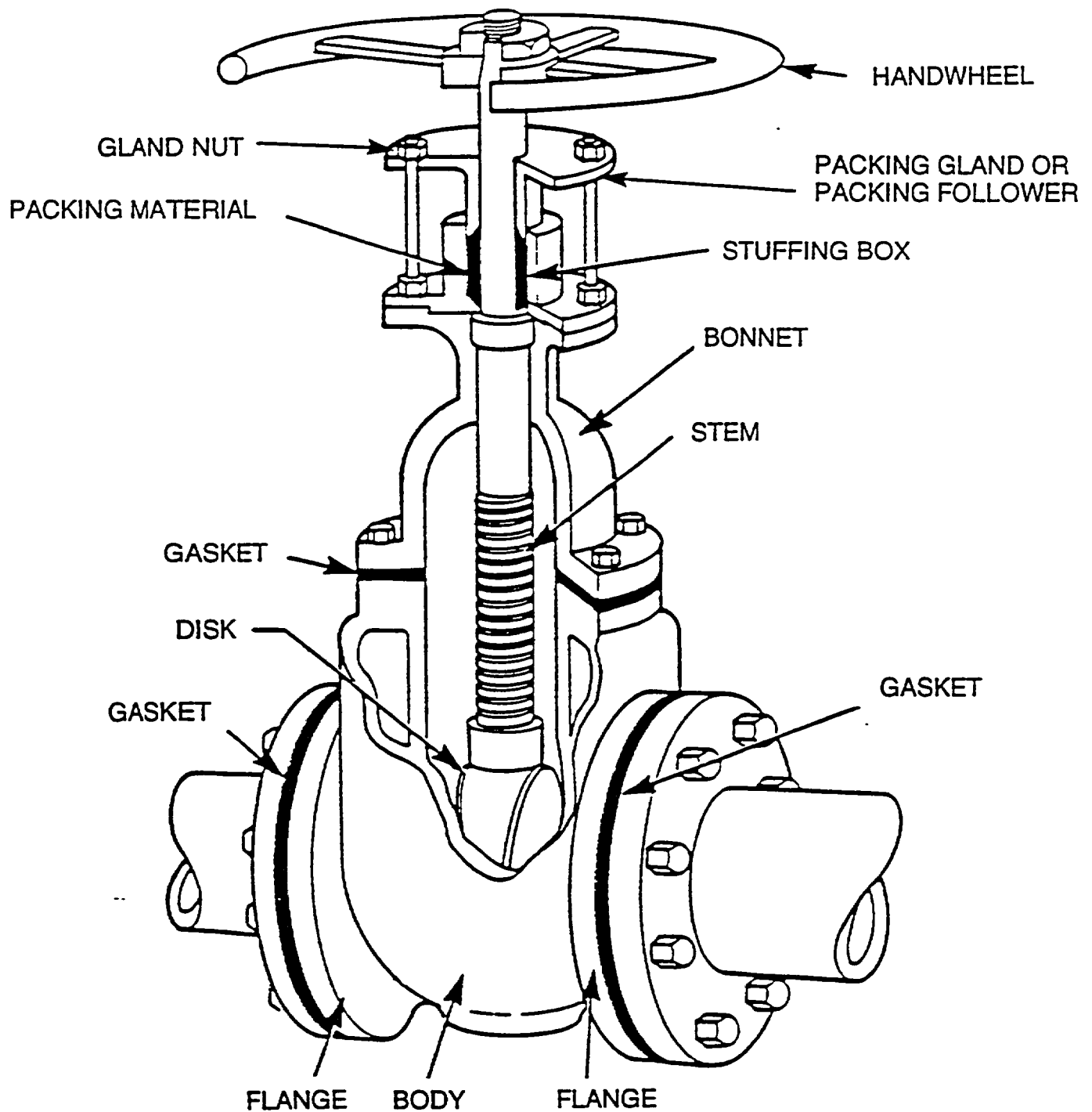


Figure 10-6. Basic Components of Gate Valves

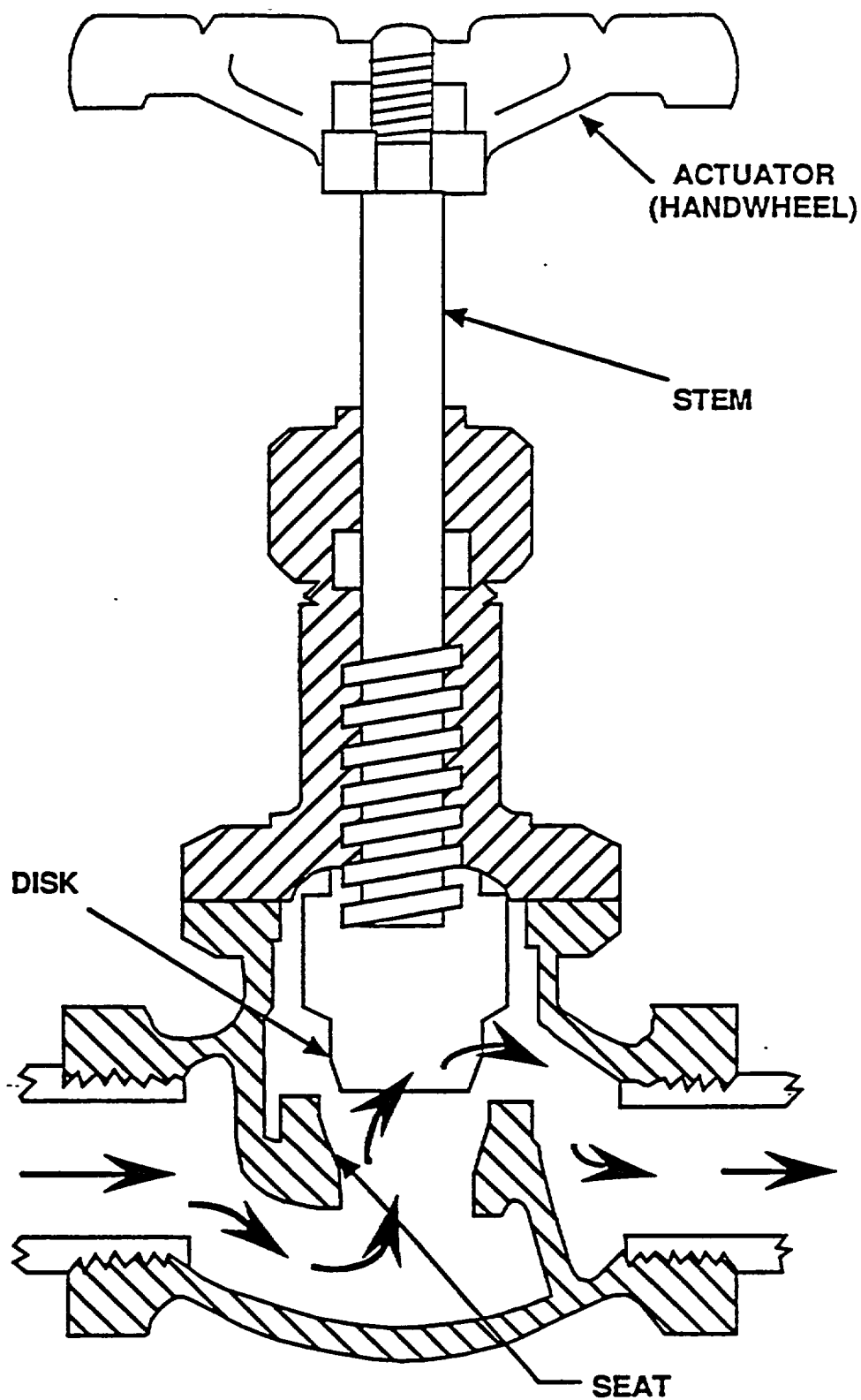


Figure 10-7. Typical Globe Valve

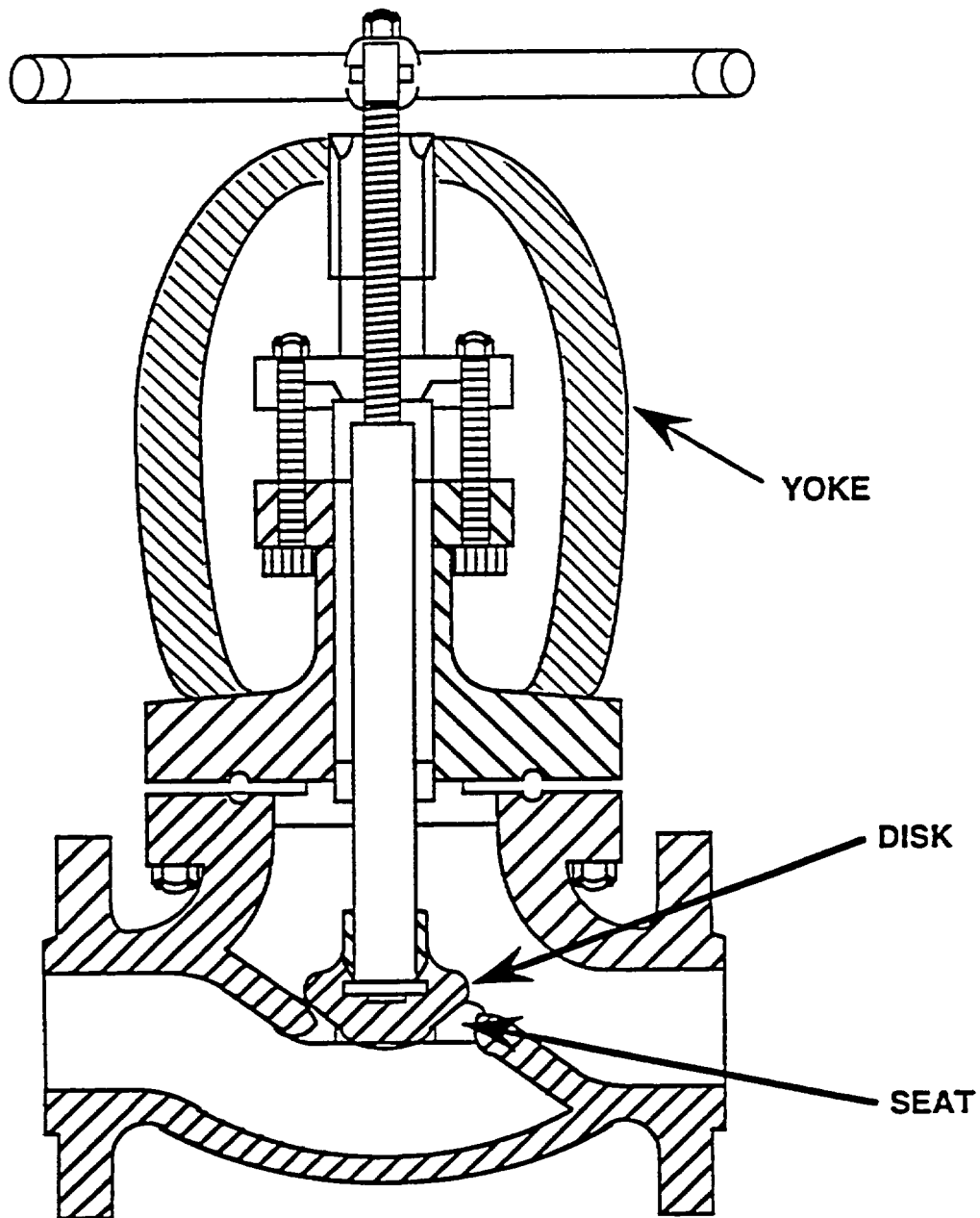


Figure 10 - 8. Globe Valve with Conventional Disk and Conical Seat

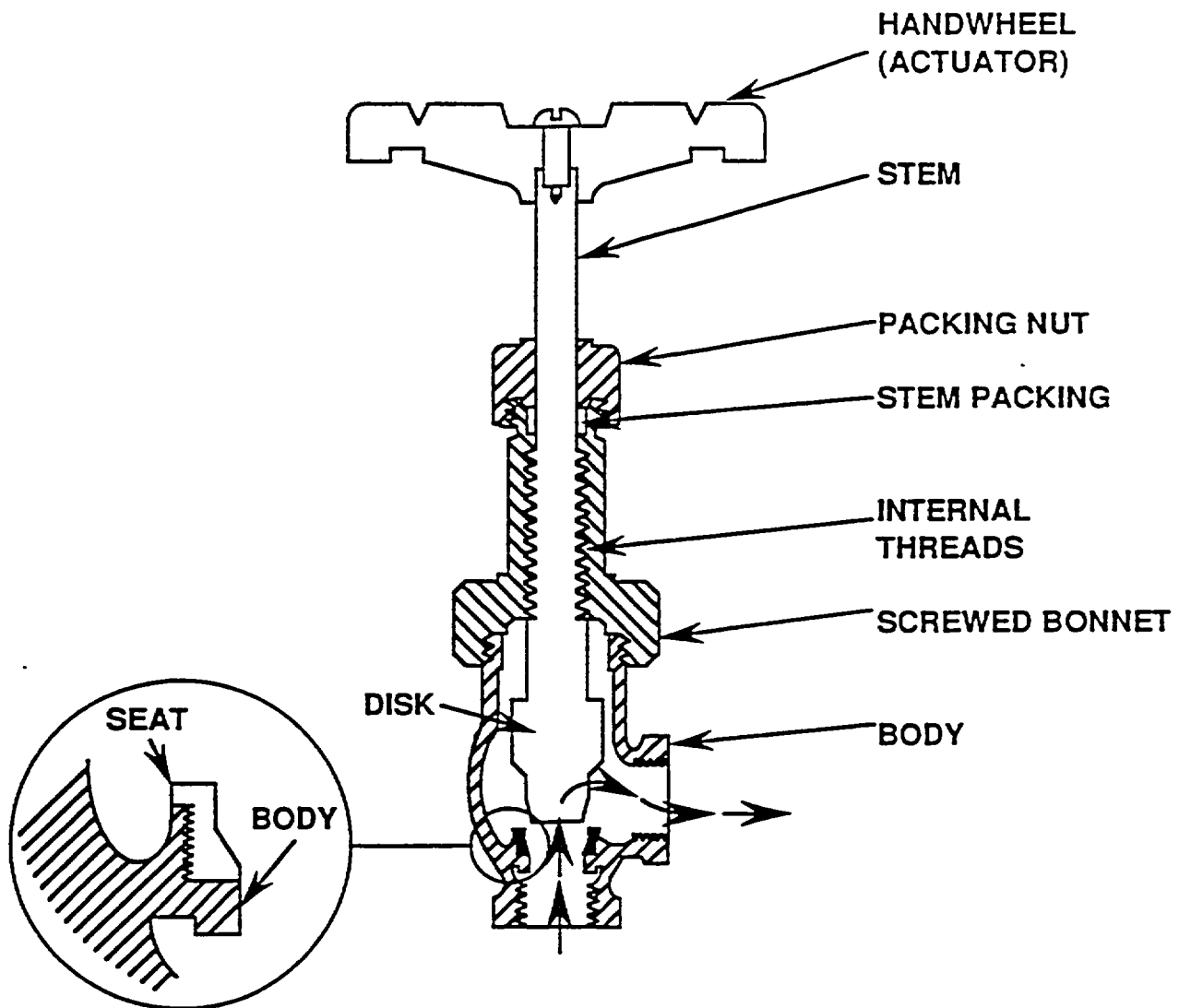


Figure 10-9. Angle Globe Valve

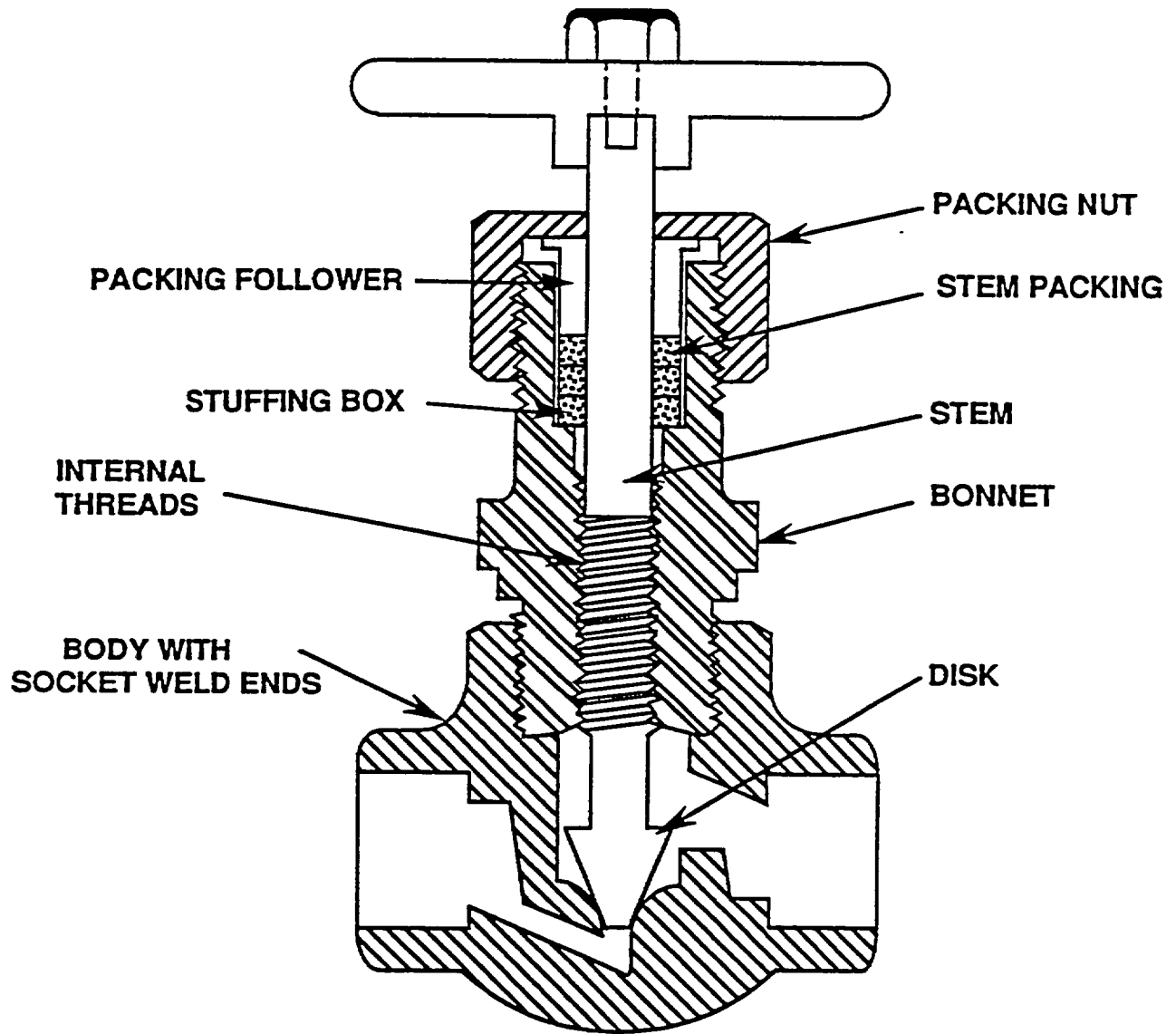


Figure 10-10. Needle Valve

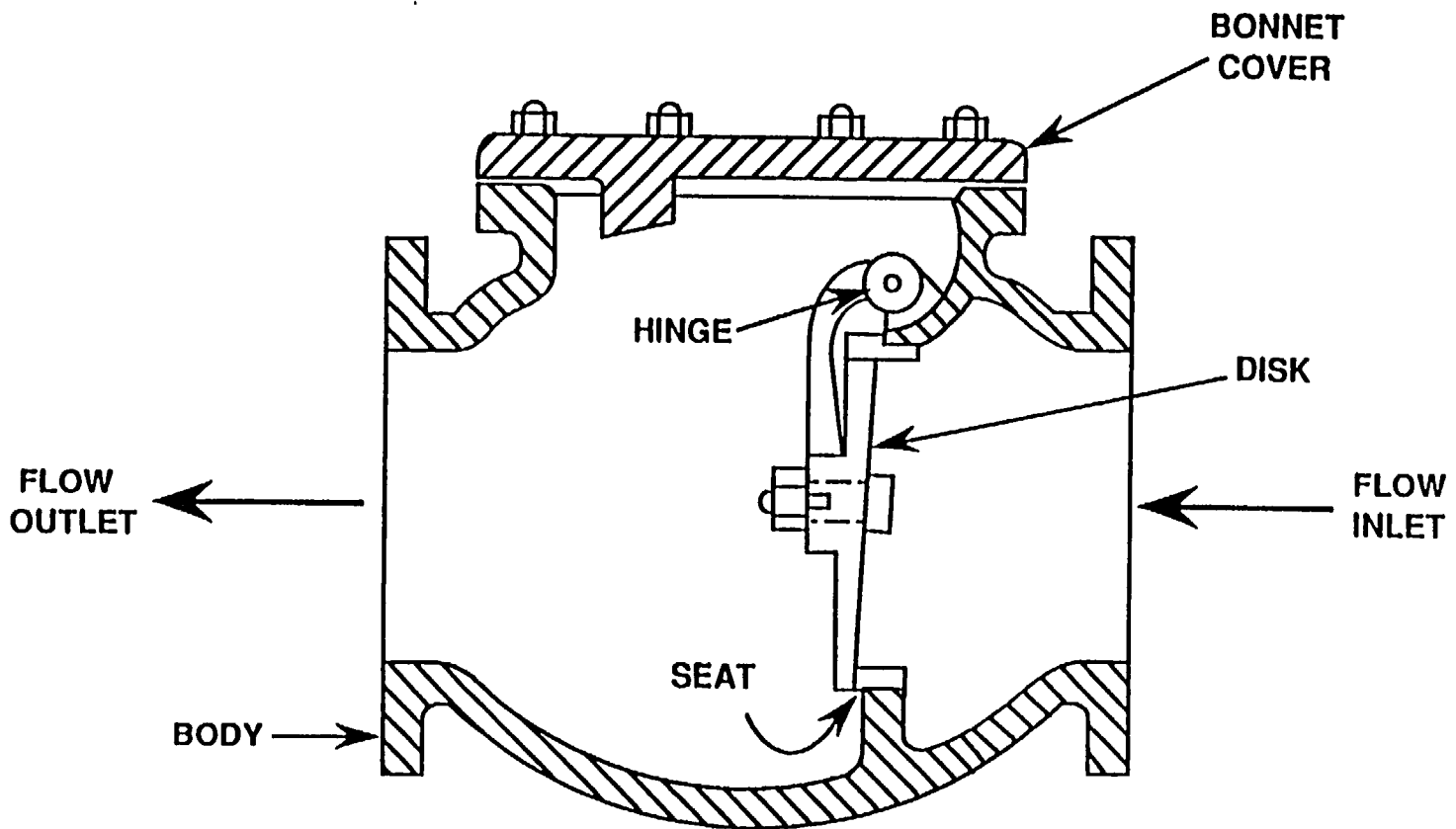


Figure 10-11. Swing - Check Valve

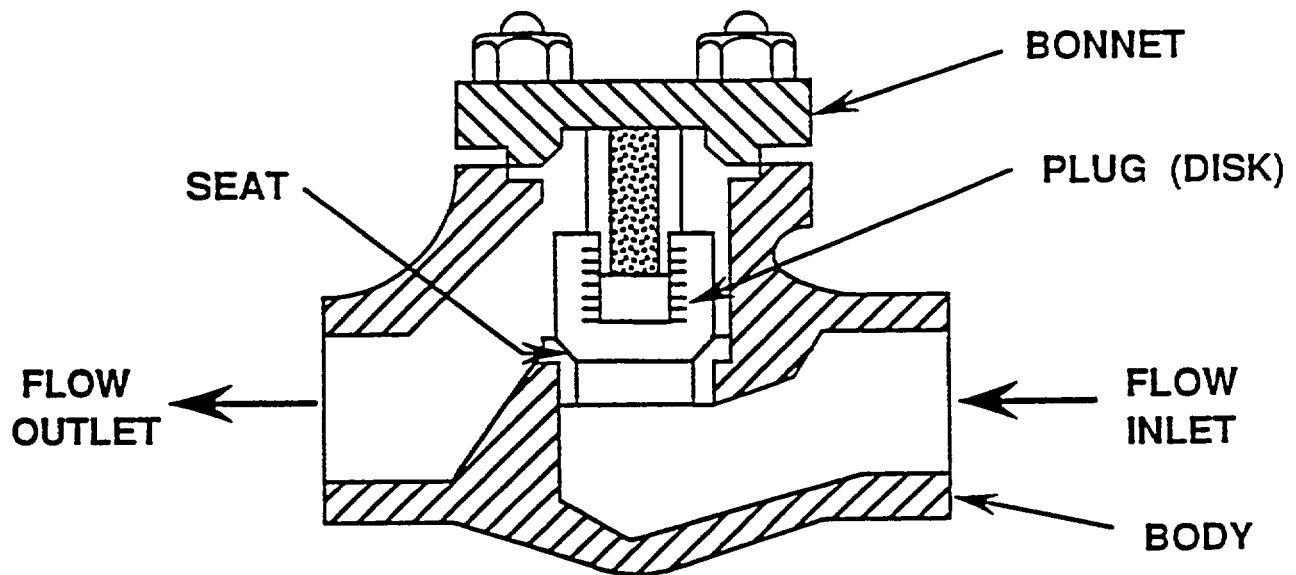


Figure 10-12. Lift - Check Valve

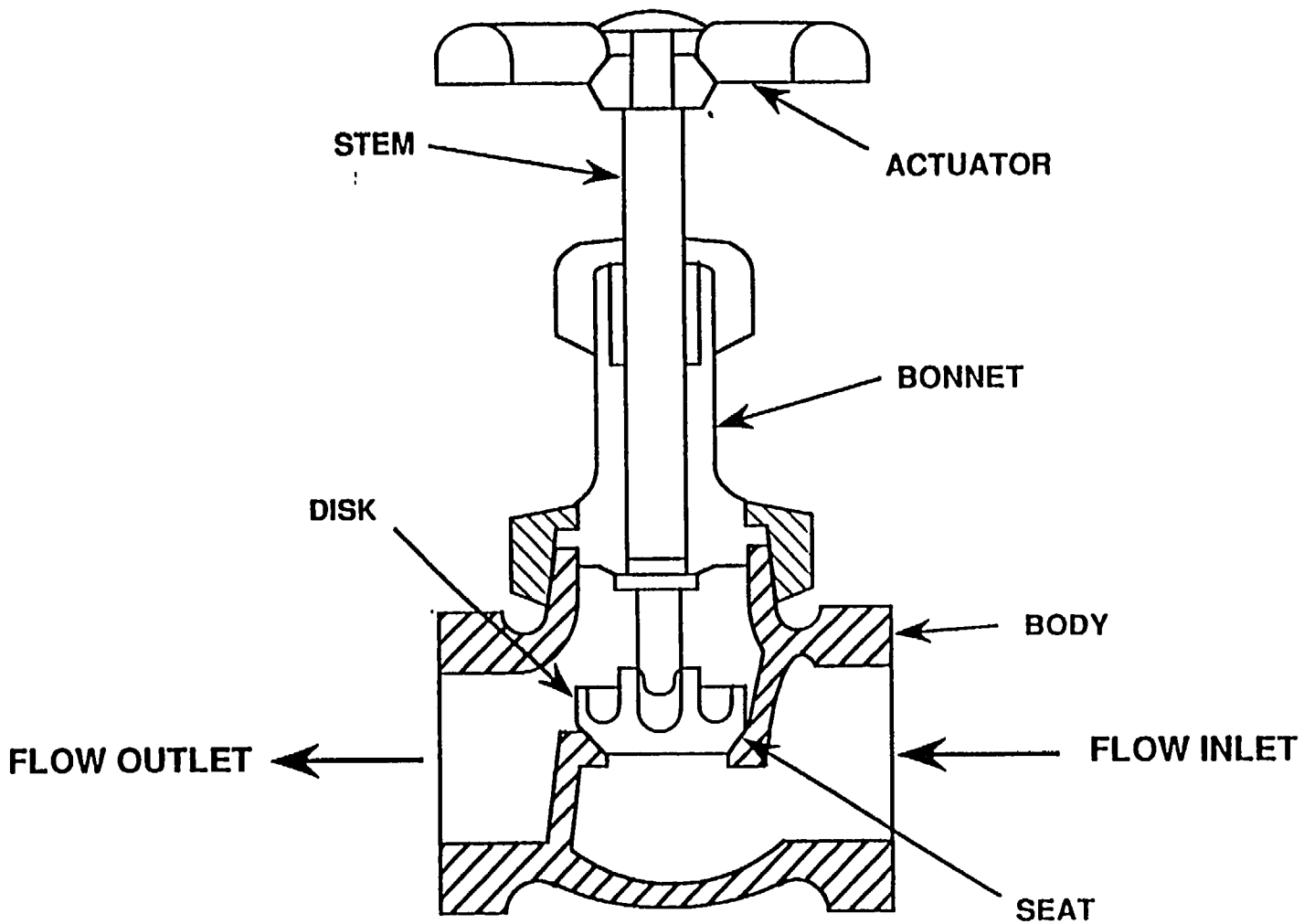


Figure 10-13. Stop - Lift - Check Valve

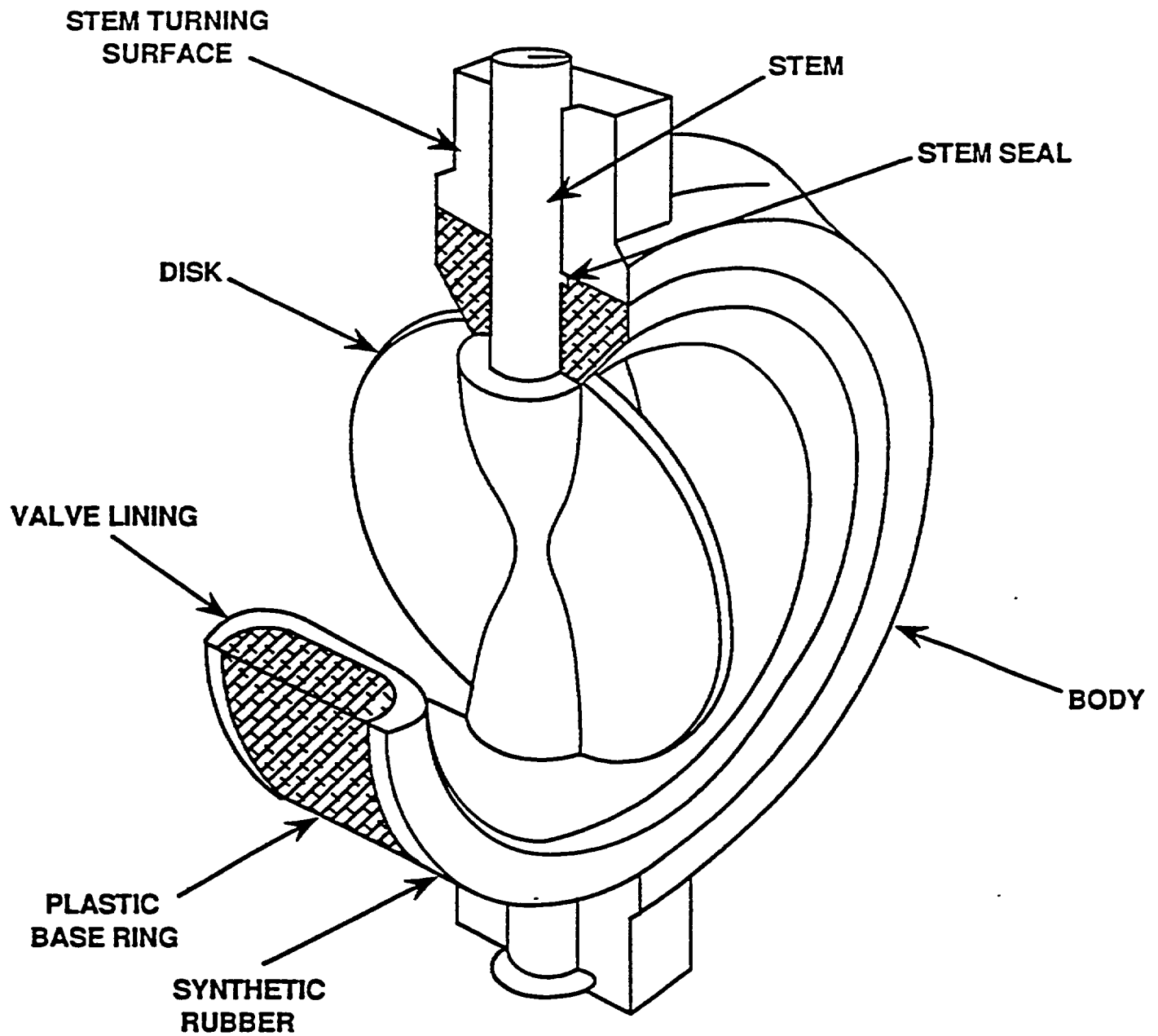


Figure 10-14. Butterfly Valve

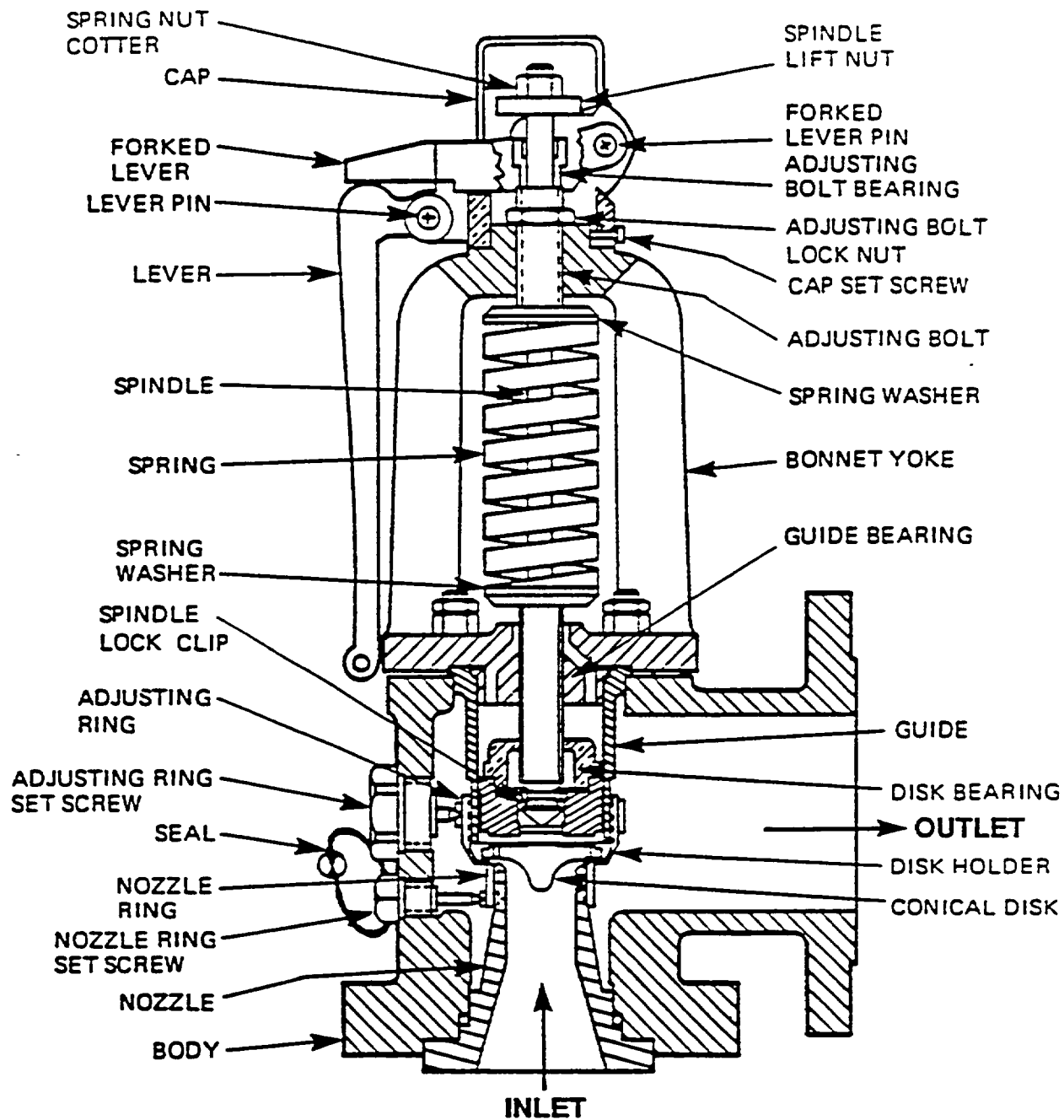


Figure 10-15. Nozzle Reaction Safety Valve

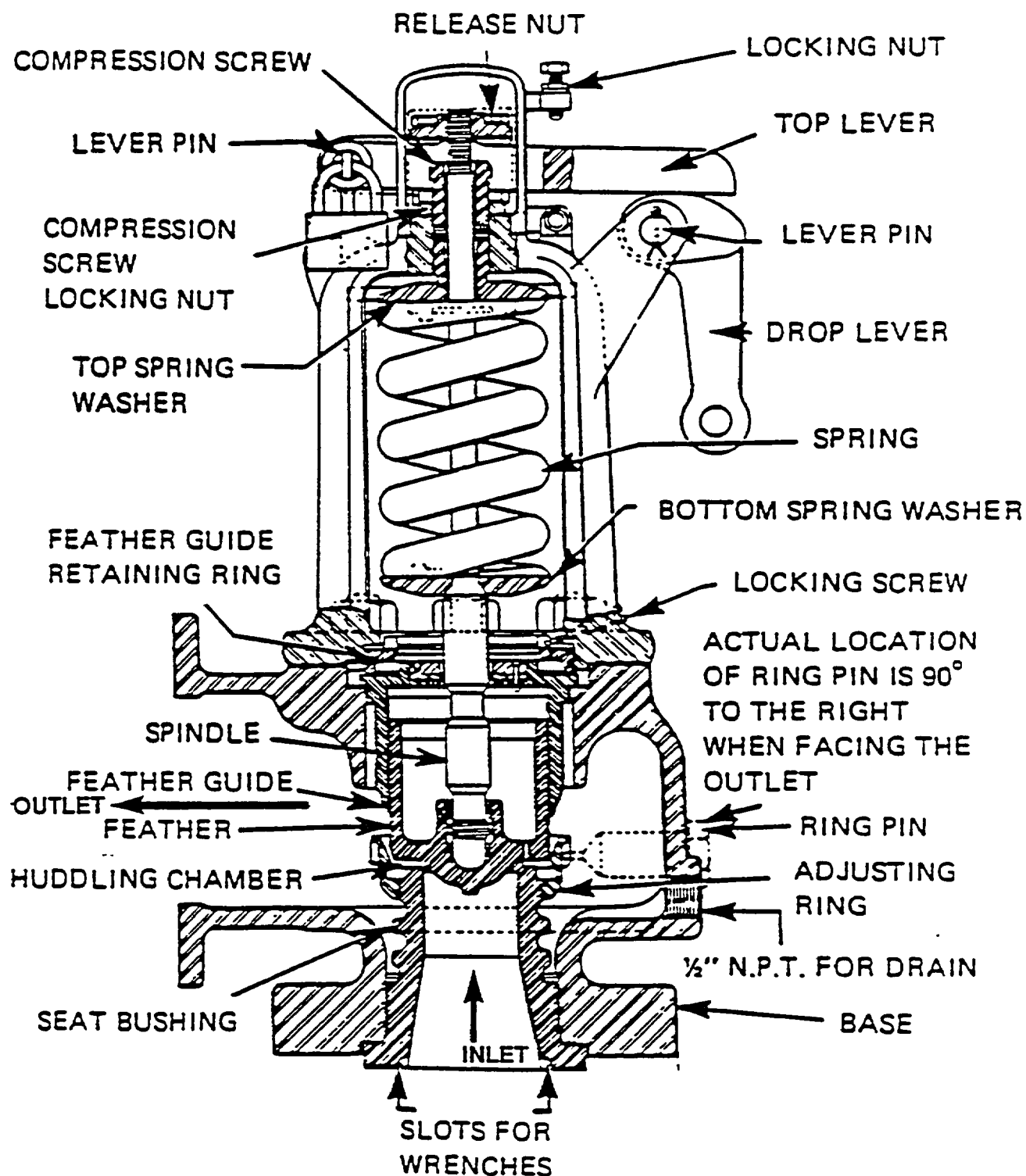


Figure 10-16. Huddling Chamber Safety Valve .

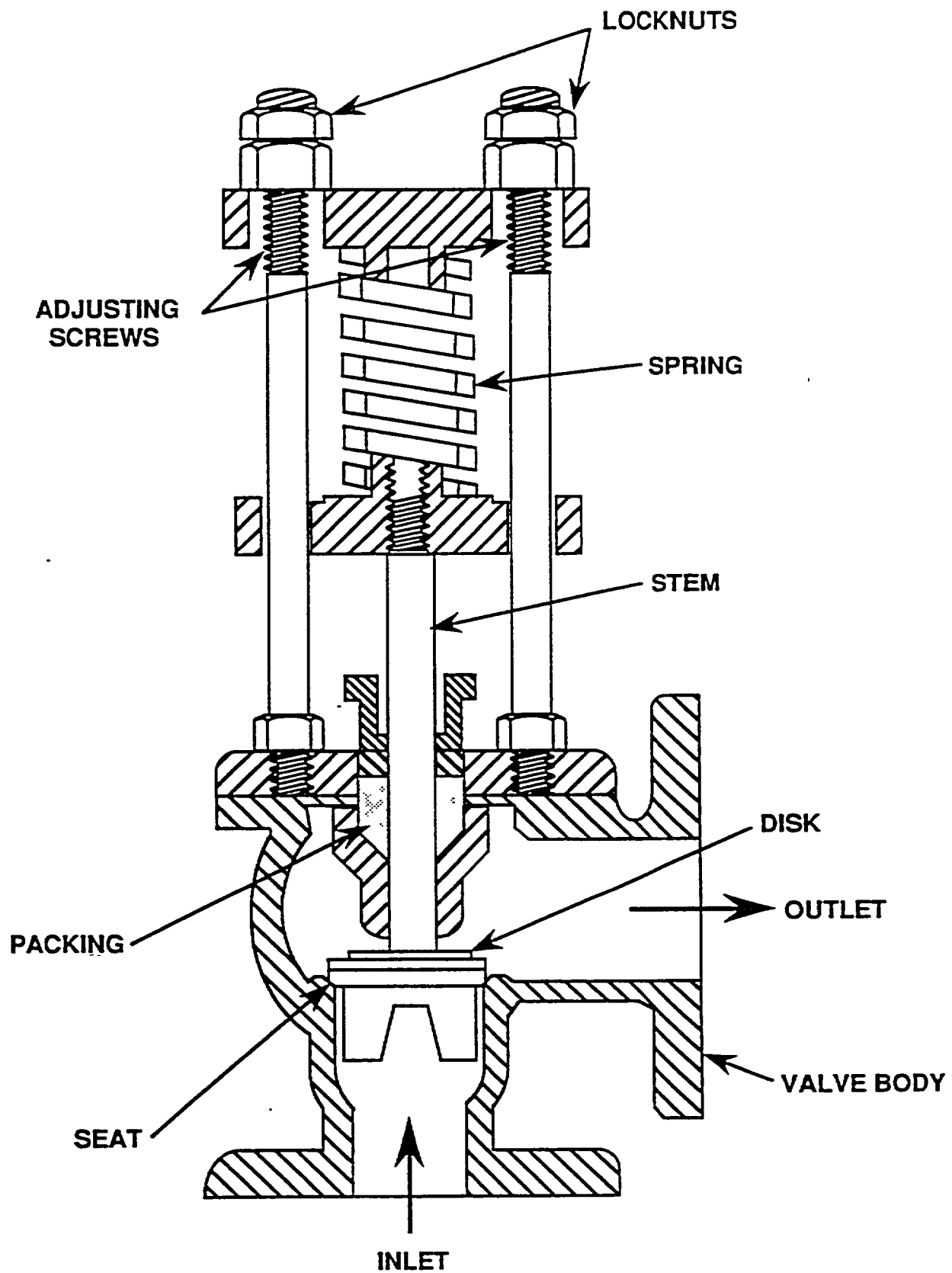
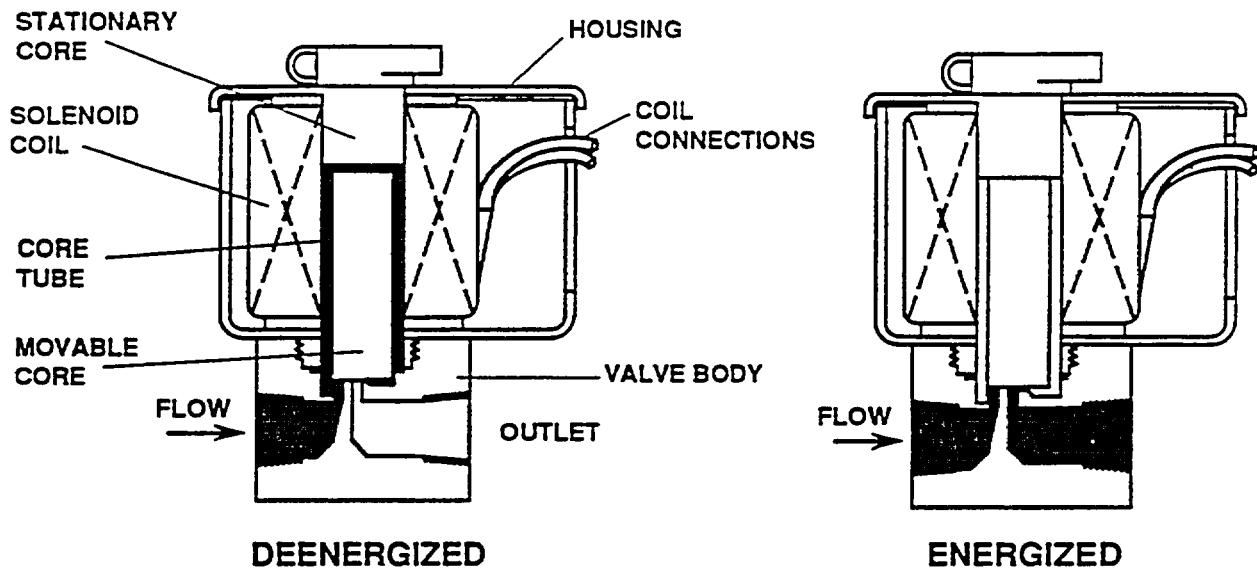
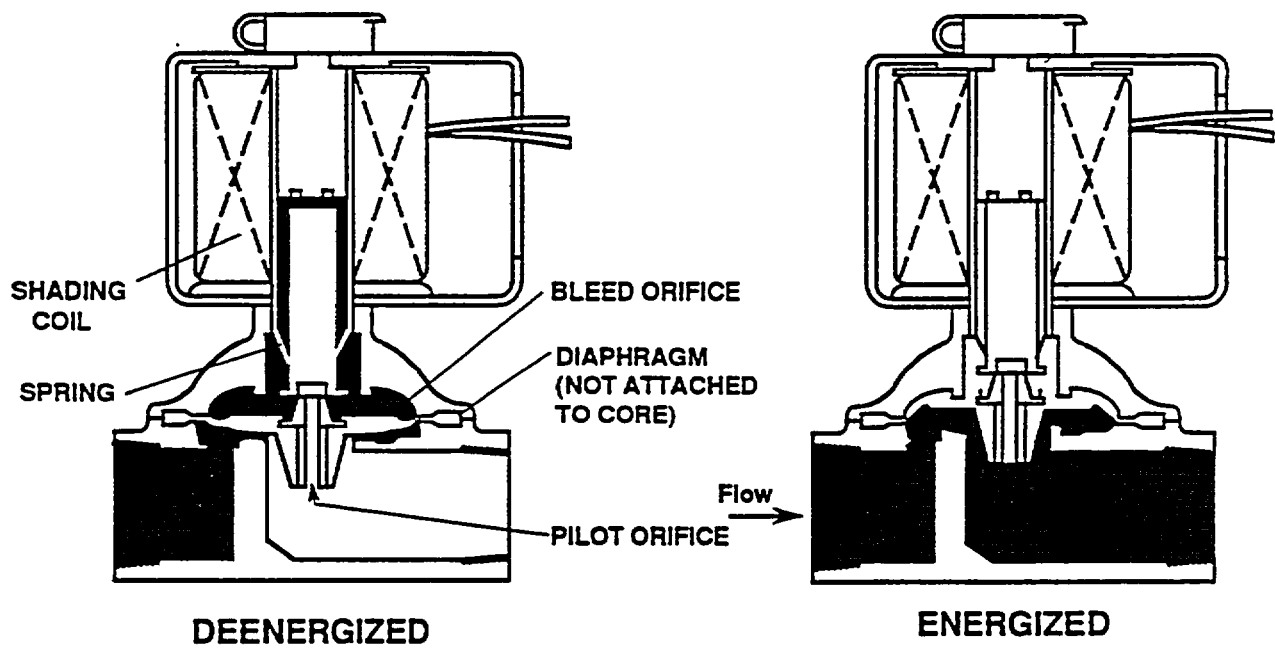


Figure 10-17. Relief Valve



A. Direct-Acting Solenoid Valve



B. Pilot-Operated Solenoid Valve

Figure 10 - 18. Direct-Acting and Pilot-Operated Solenoid Valves

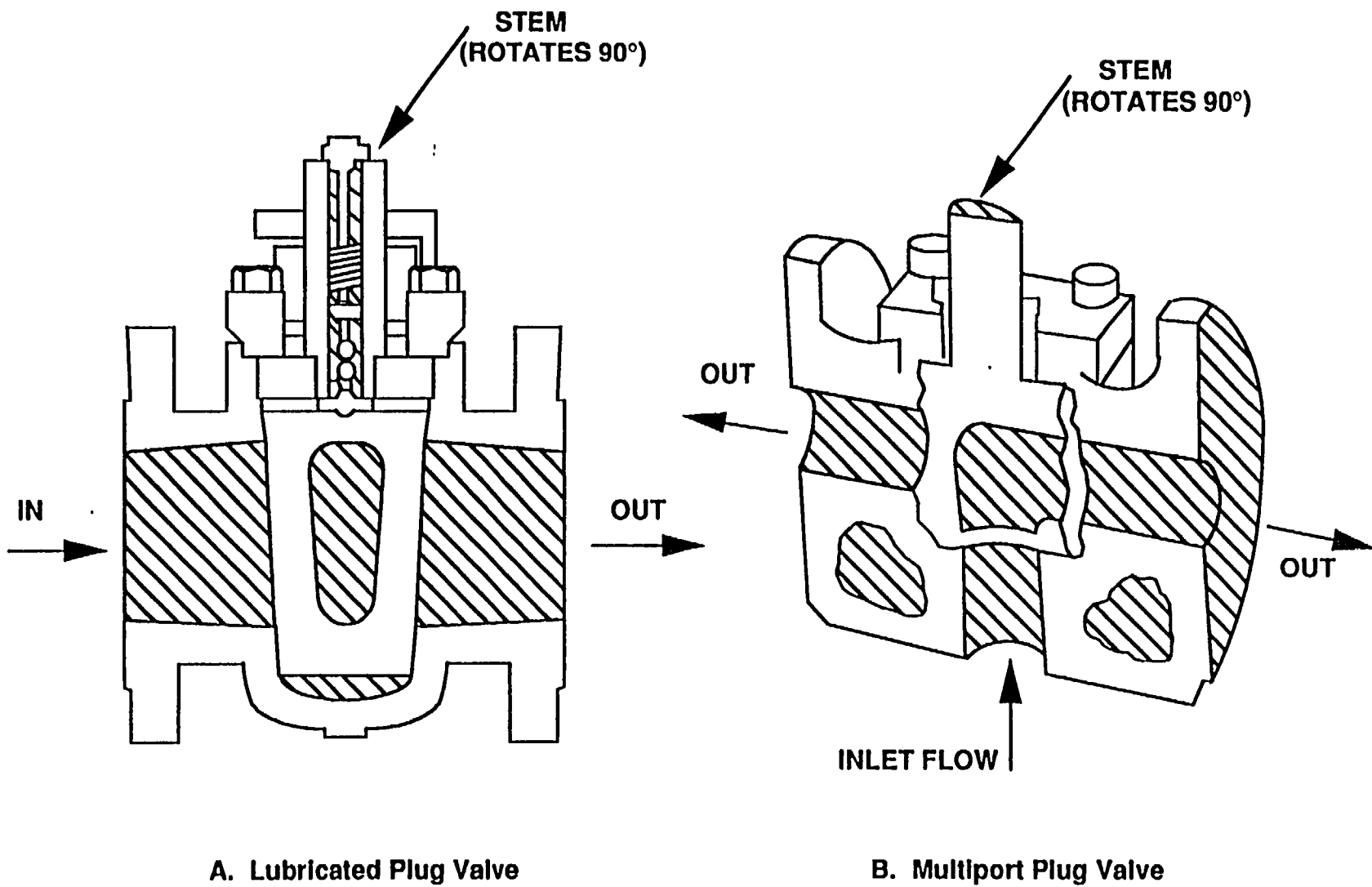


Figure 10-19. Two Types of Plug Valves

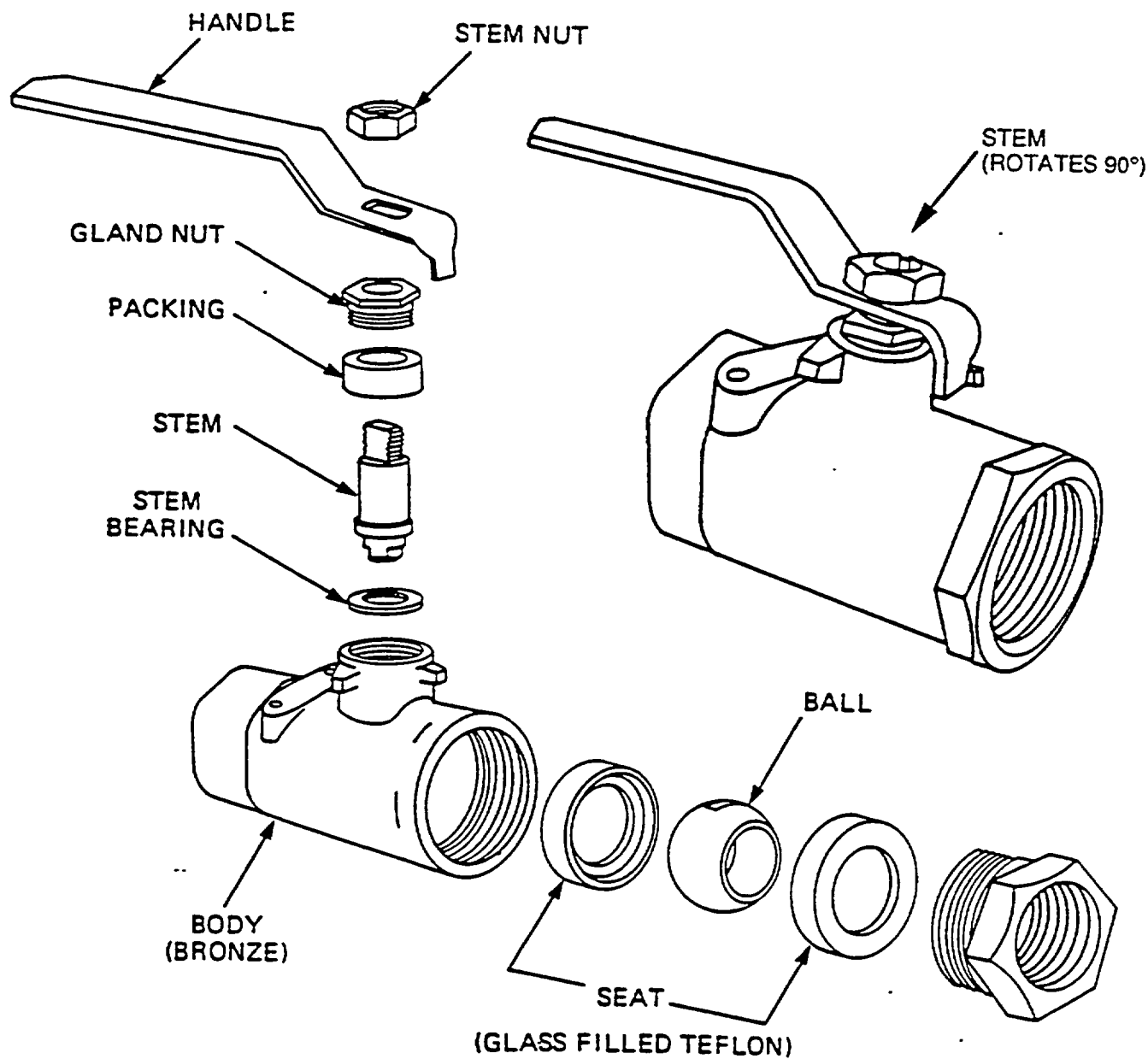
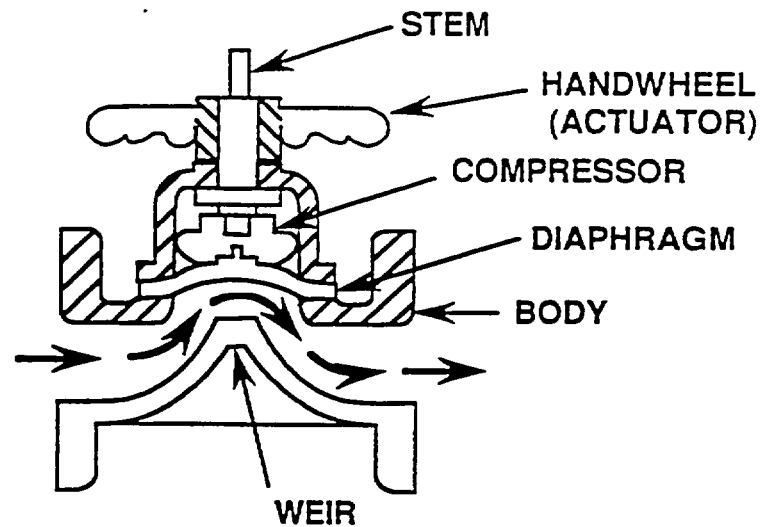
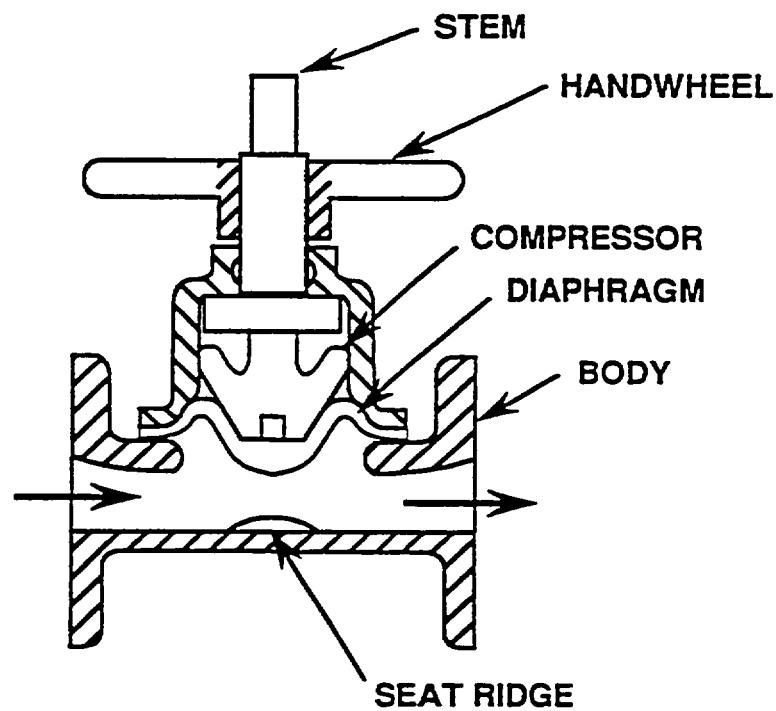


Figure 10-20. Ball Valve



A. Weir-Type Diaphragm Valve



B. Straightway-Type Diaphragm Valve

Figure 10 - 21. Diaphragm Valves

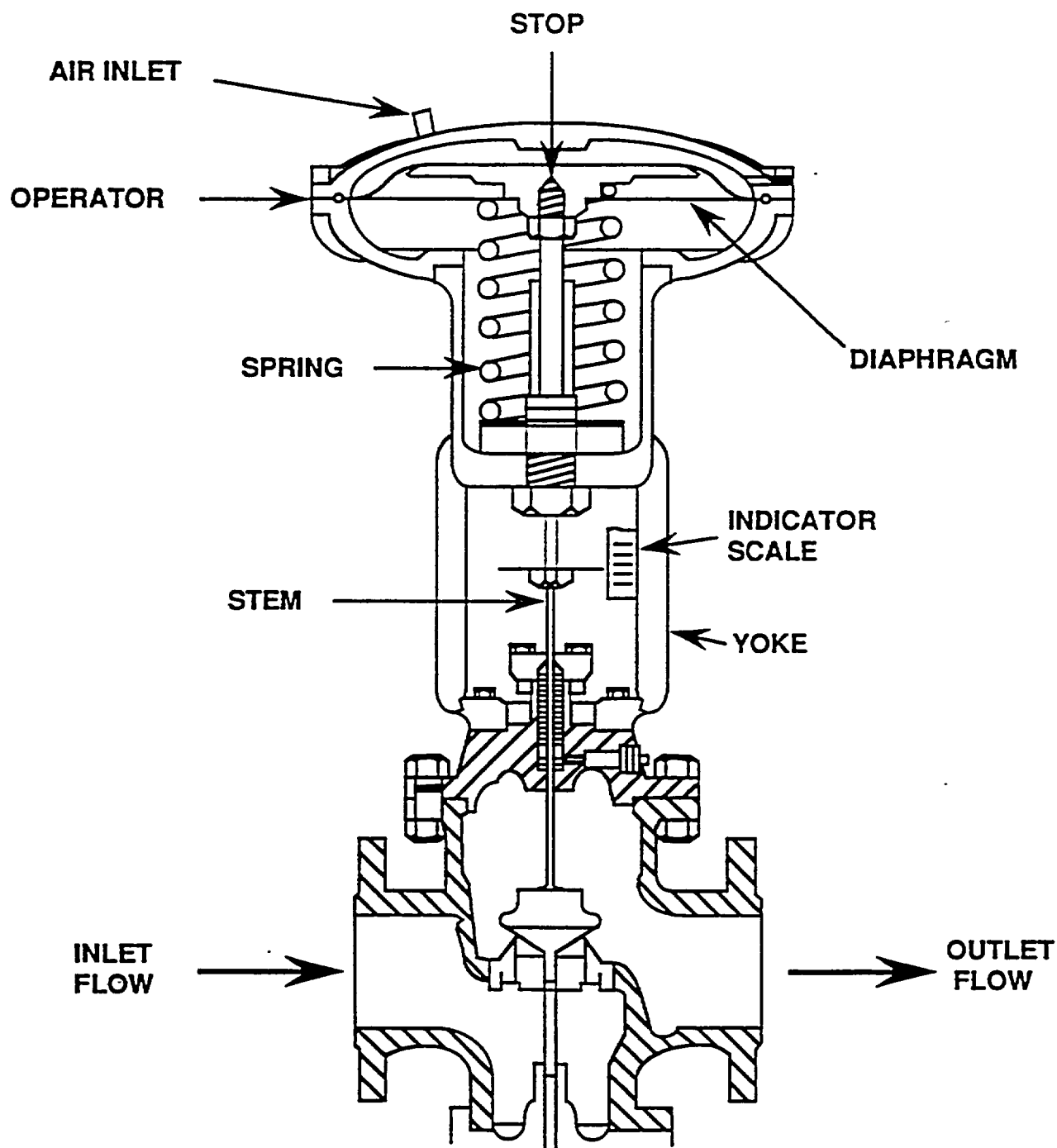


Figure 10-22. Air-Operated Single-Seated Control Valve

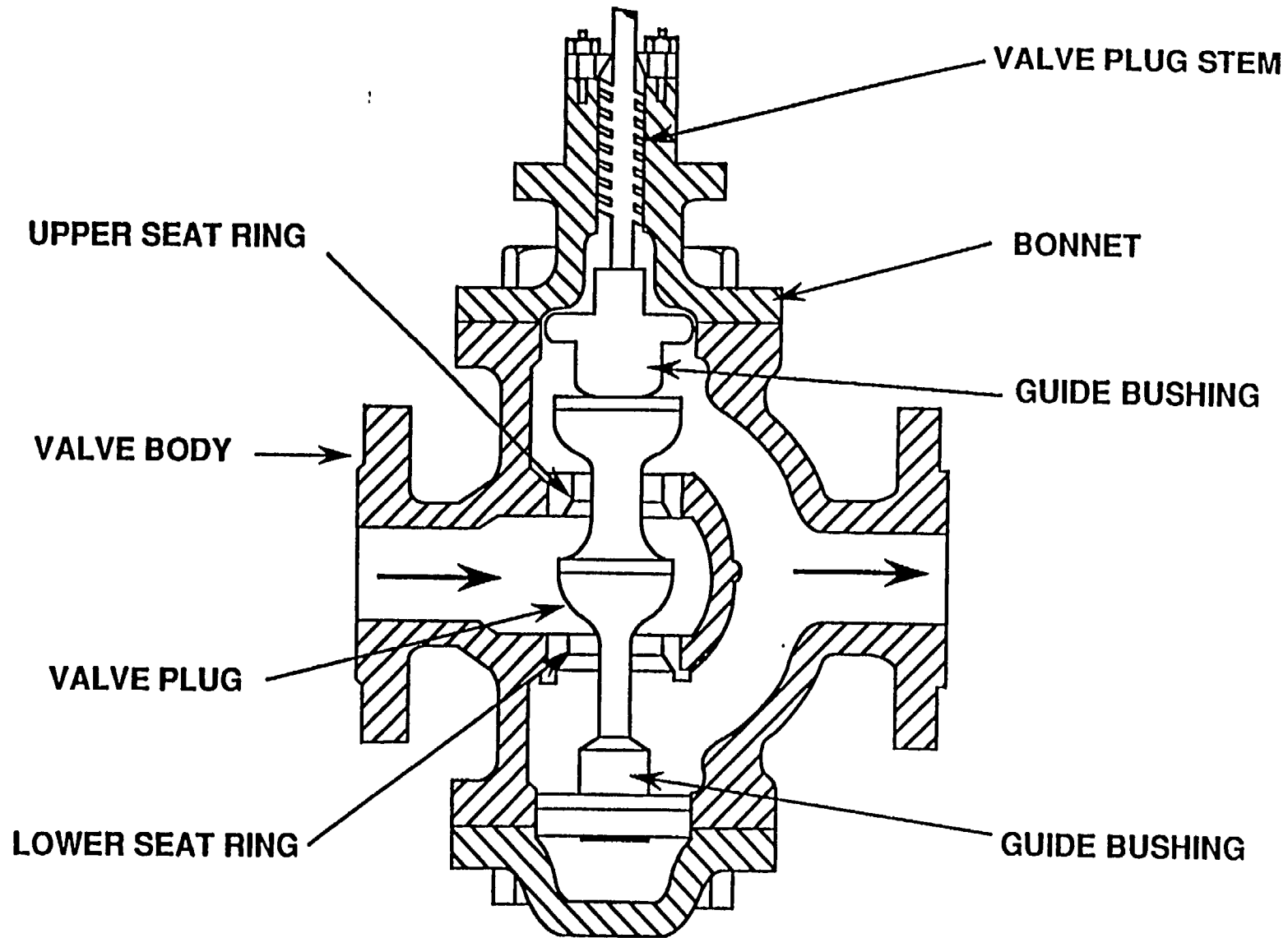


Figure 10-23. Double-Seated Control Valve

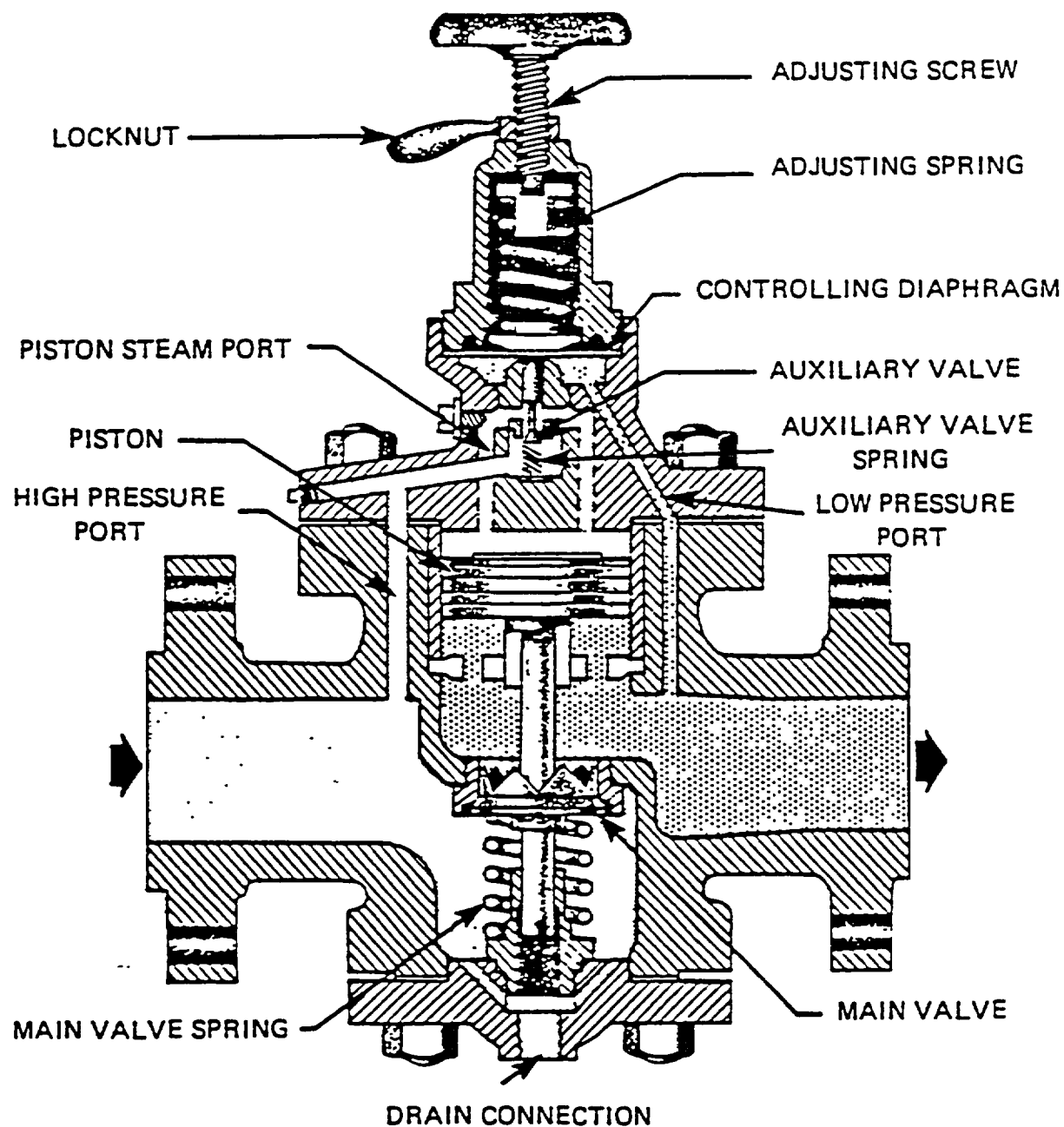


Figure 10-24. Self-Contained Pressure-Reducing Valve

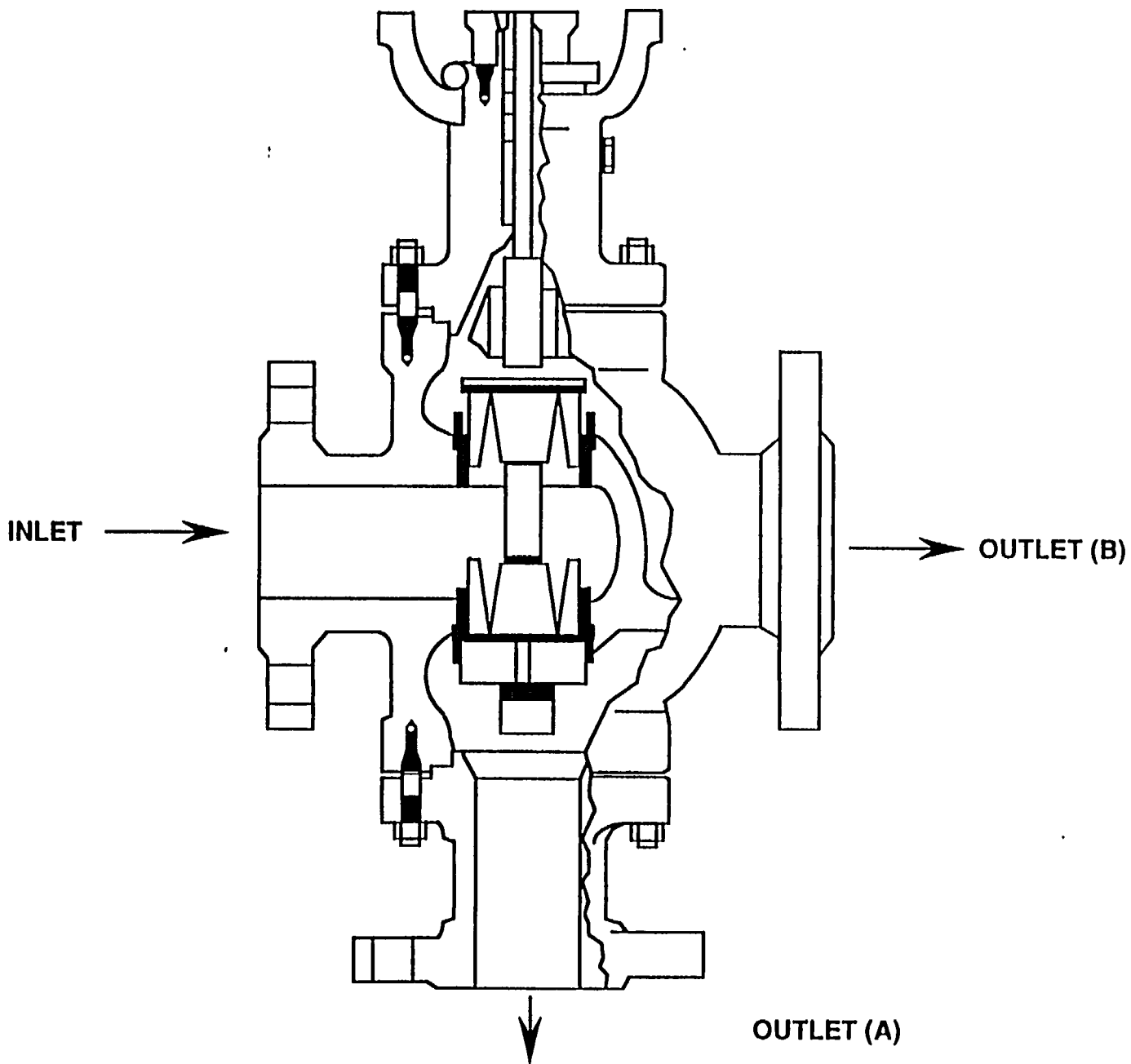


Figure 10-25. Three-Way Valve for Diverting Service

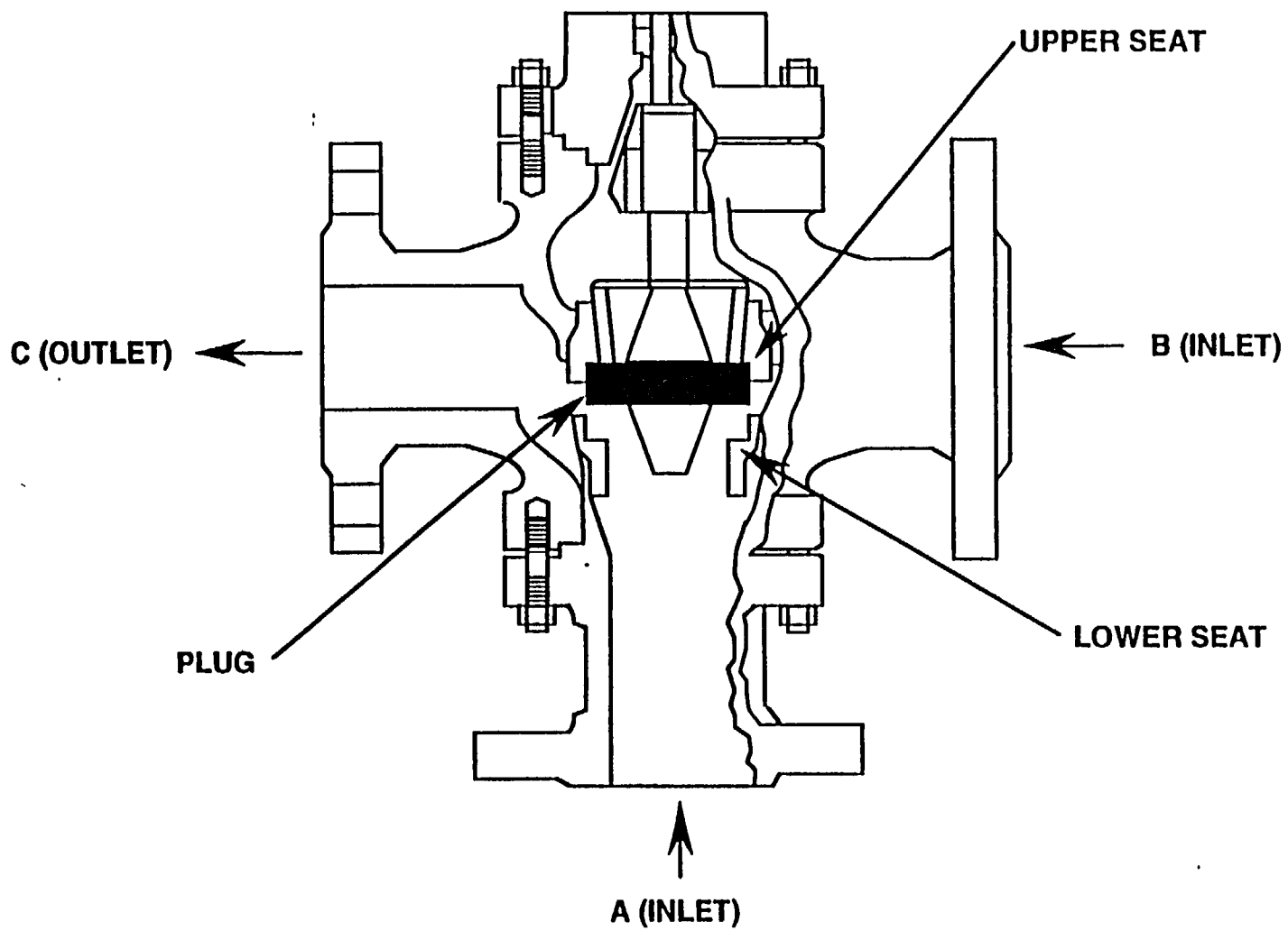
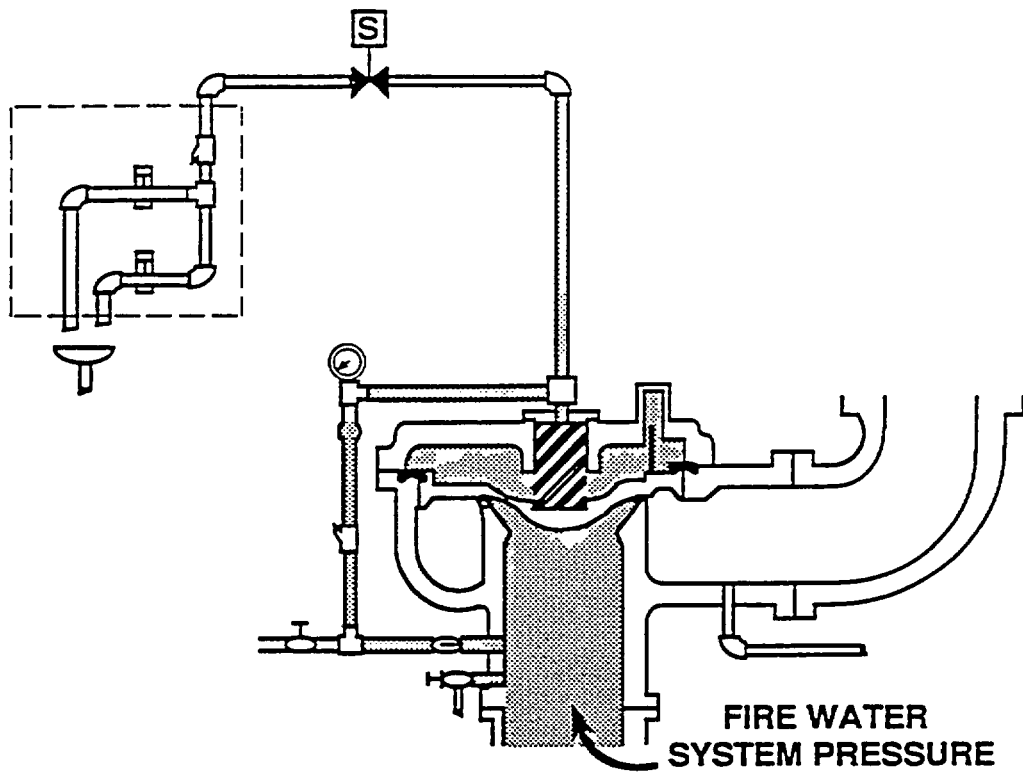
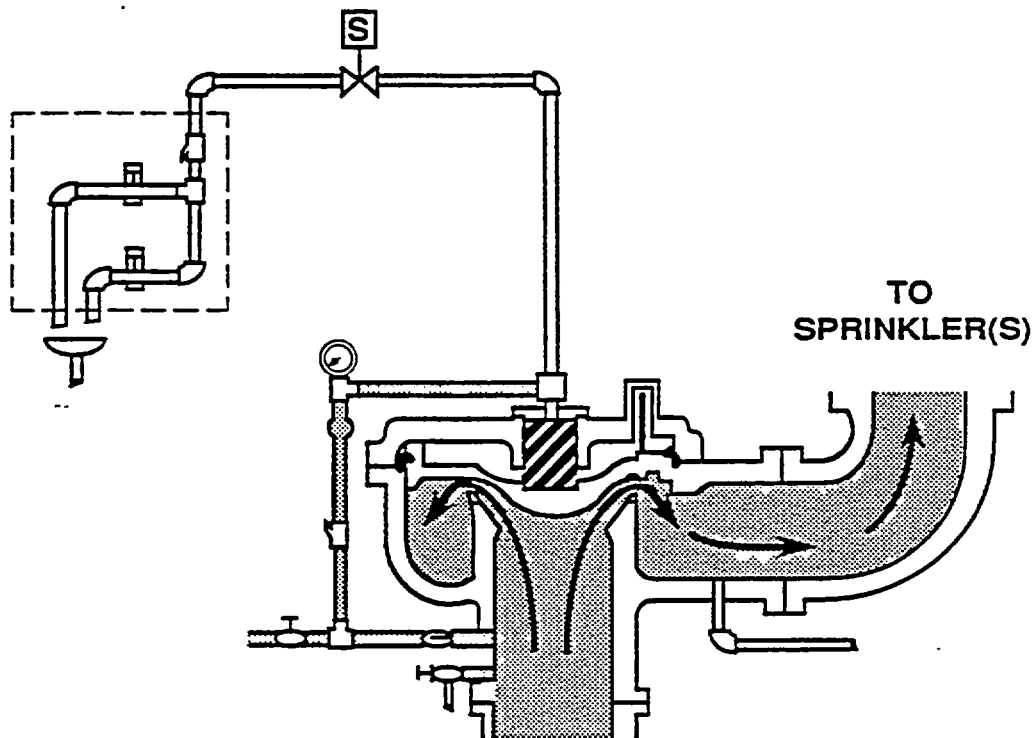


Figure 10-26. Three-way Valve for Combining Service



A. DELUGE VALVE CLOSED



B. DELUGE VALVE OPEN

Figure 10 - 27. Deluge Valve

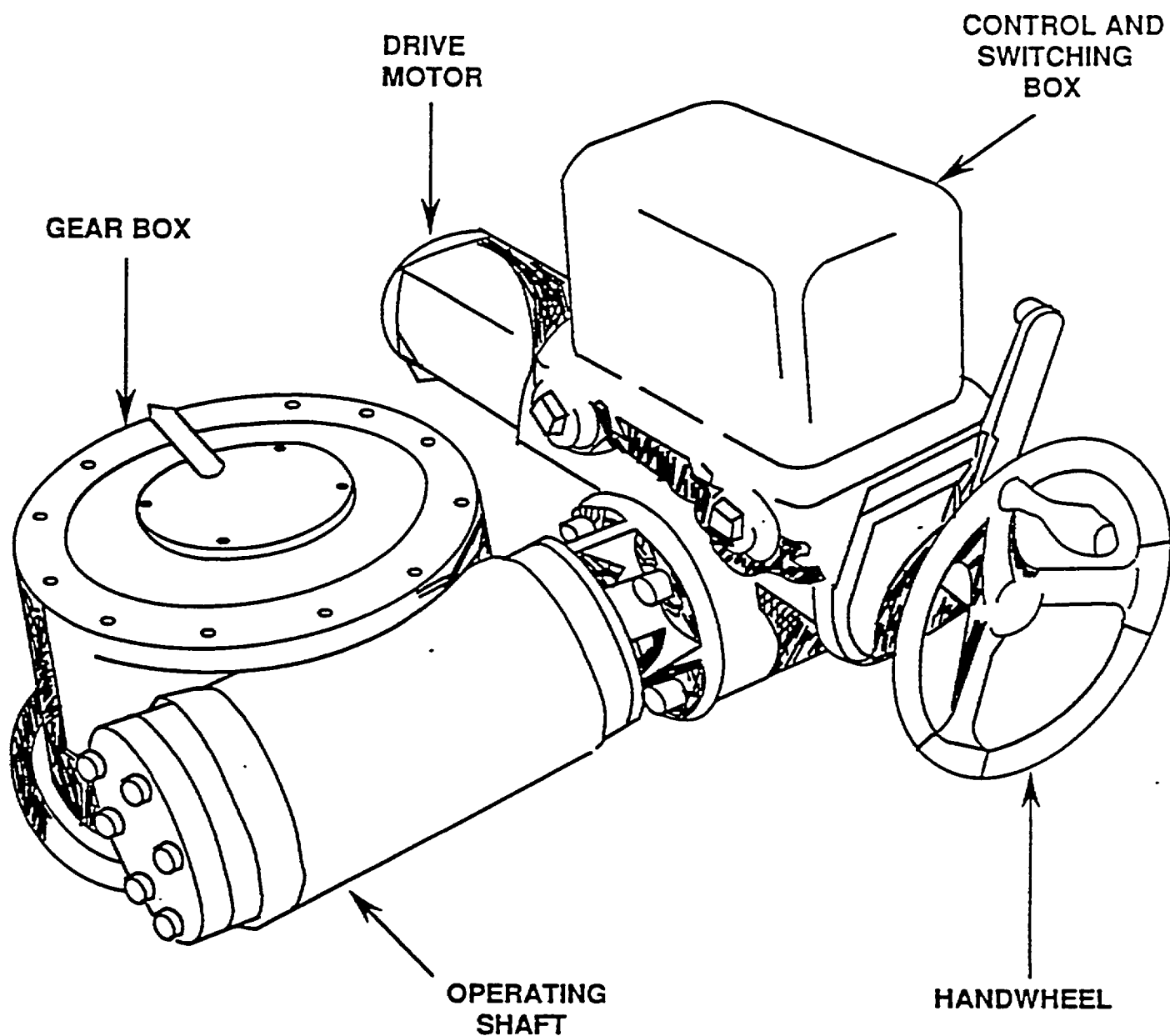
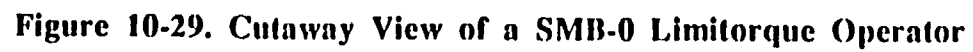
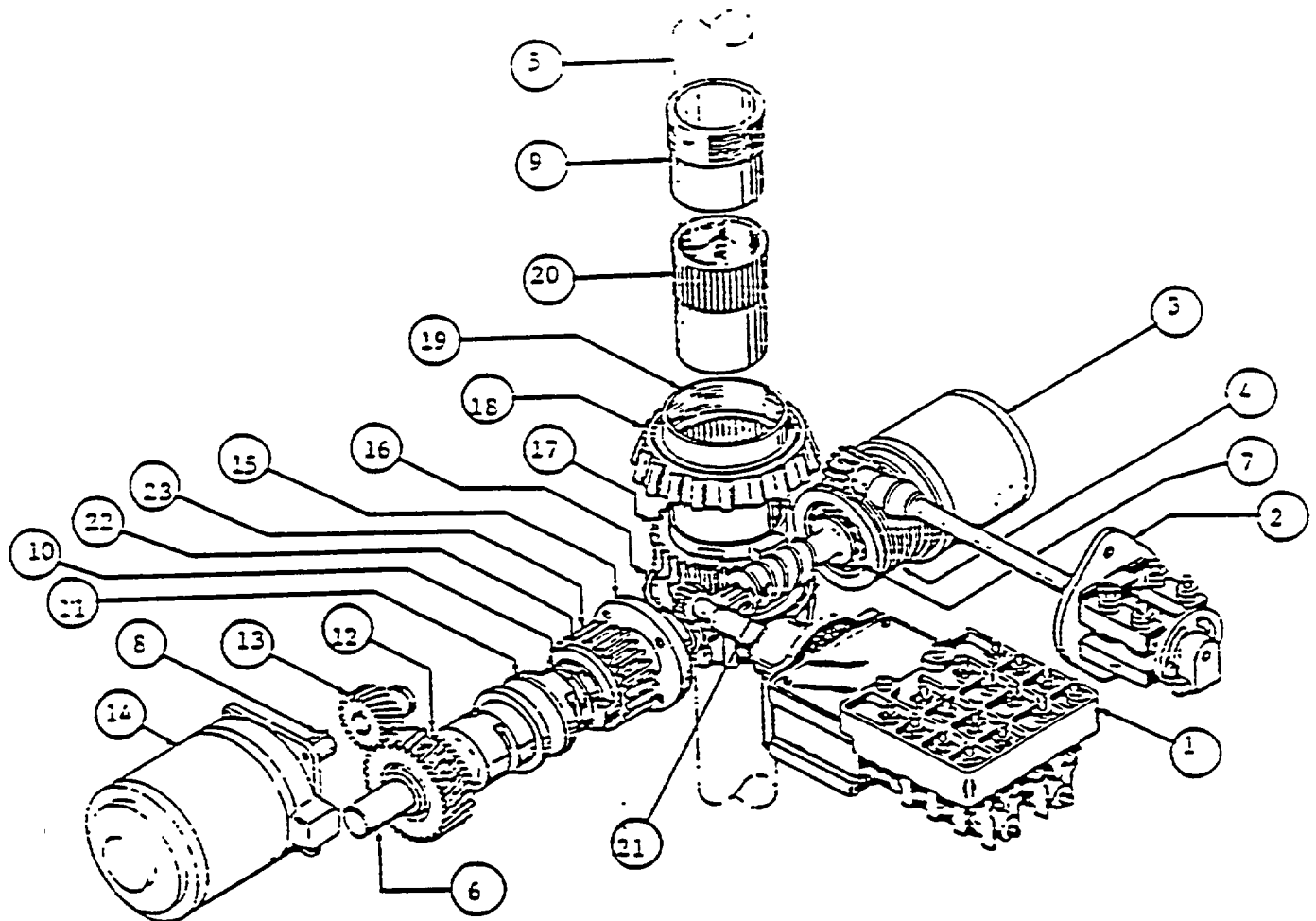


Figure 10-28. Electric Valve Operator





- | | |
|---------------------------------|------------------------------|
| 1. Geared Limit Switch Assembly | 12. Worm Shaft Clutch Gear |
| 2. Torque Switch | 13. Motor Pinion |
| 3. Torque Limit Sleeve | 14. Motor |
| 4. Bearing Cartridge Stem | 15. Bearing Cartridge Cap |
| 5. Valve Stem | 16. Thrust Bearing |
| 6. Worm Shaft | 17. Worm Gear |
| 7. Bearing | 18. Thrust Bearing |
| 8. Drive Shaft Key | 19. Drive Sleeve |
| 9. Locking Nut | 20. Stem Nut |
| 10. Fork Return Spring | 21. Worm |
| 11. Worm Shaft Clutch | 22. Spring Ring |
| | 23. Hand Wheel Clutch Pinion |

Figure 10-30. SMB-0 Limitorque Operator

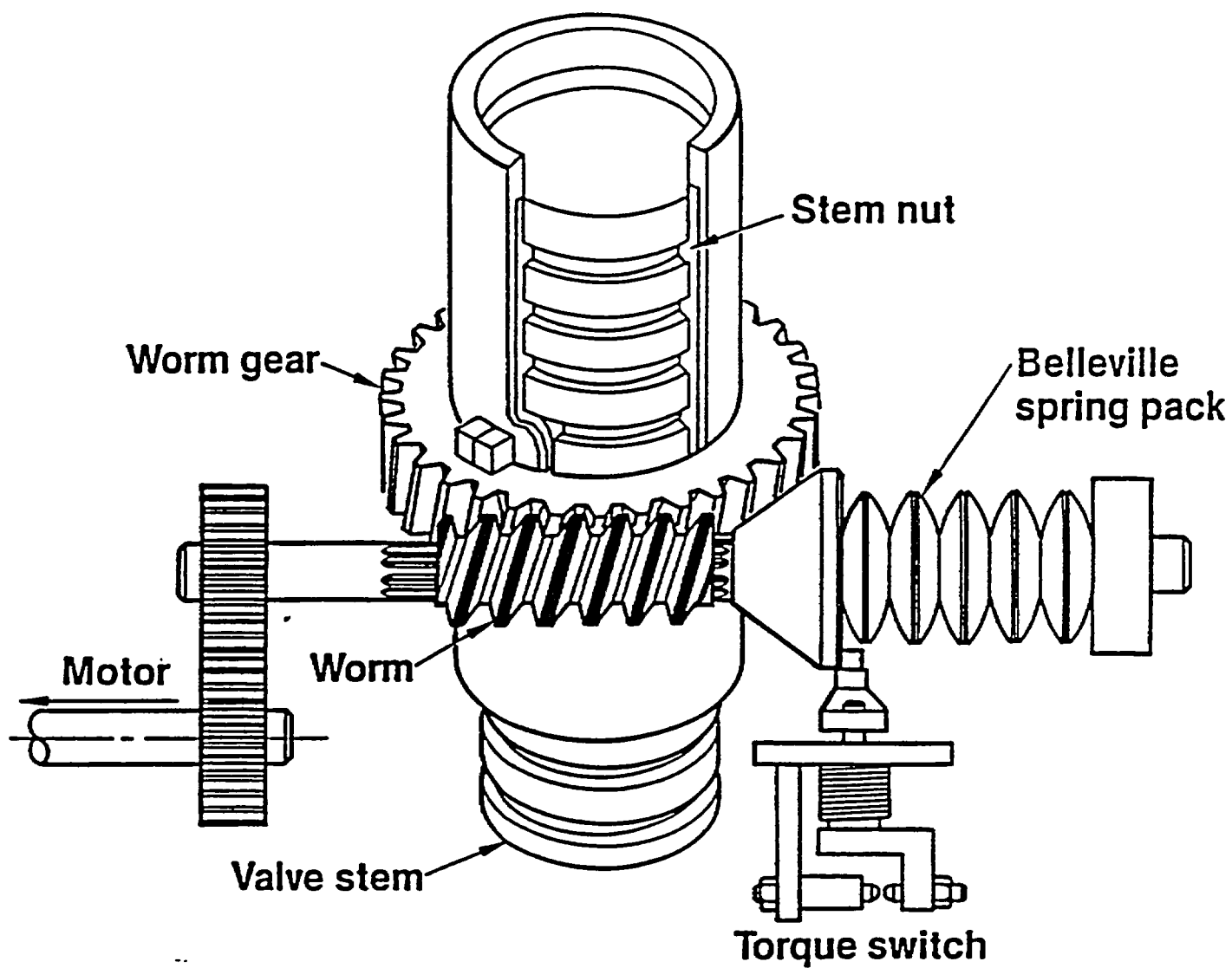


Figure 10-31. Simplified Worm Operation Diagram

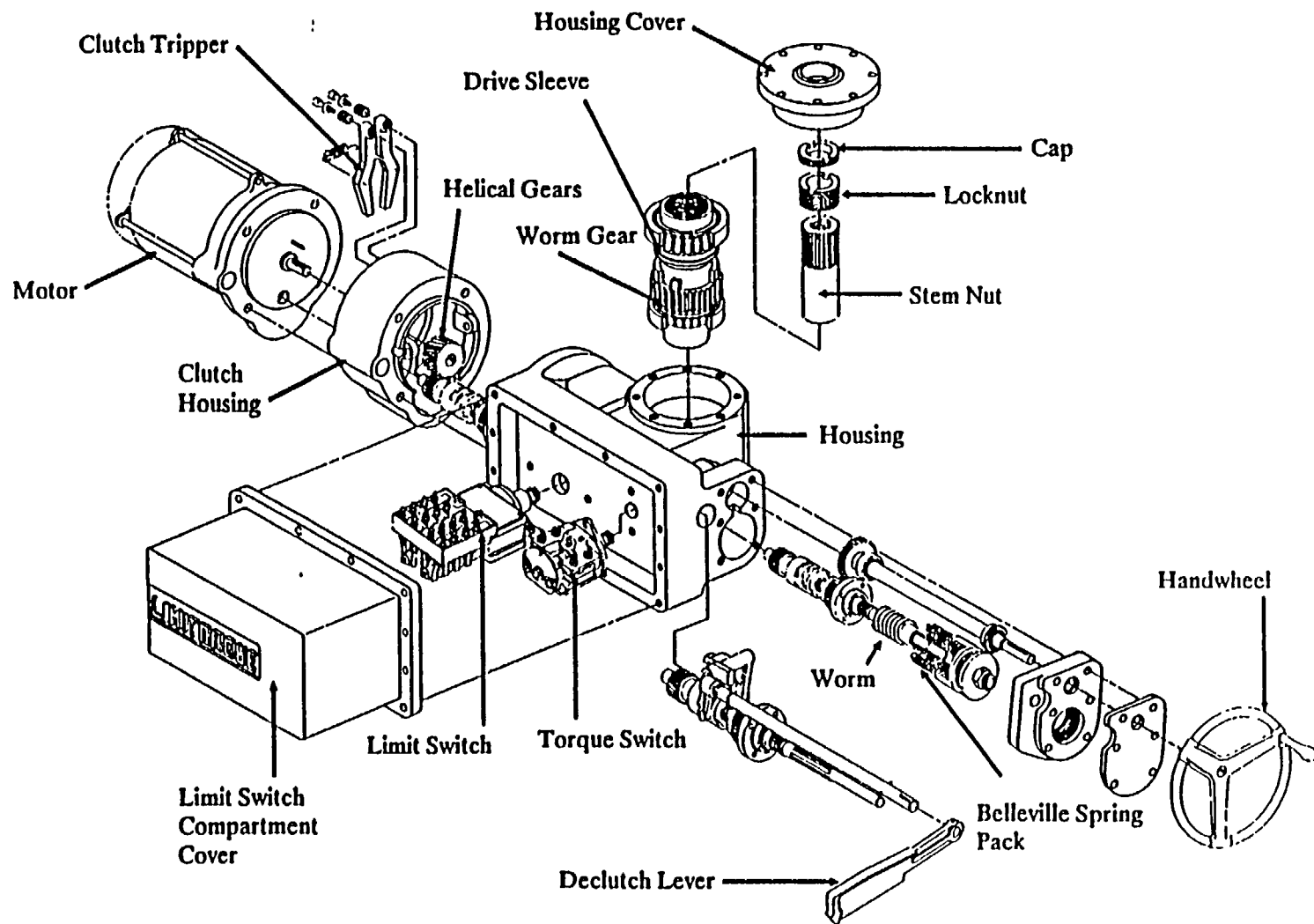


Figure 10-32. SMB-0 Limitorque Operator (Exploded View)

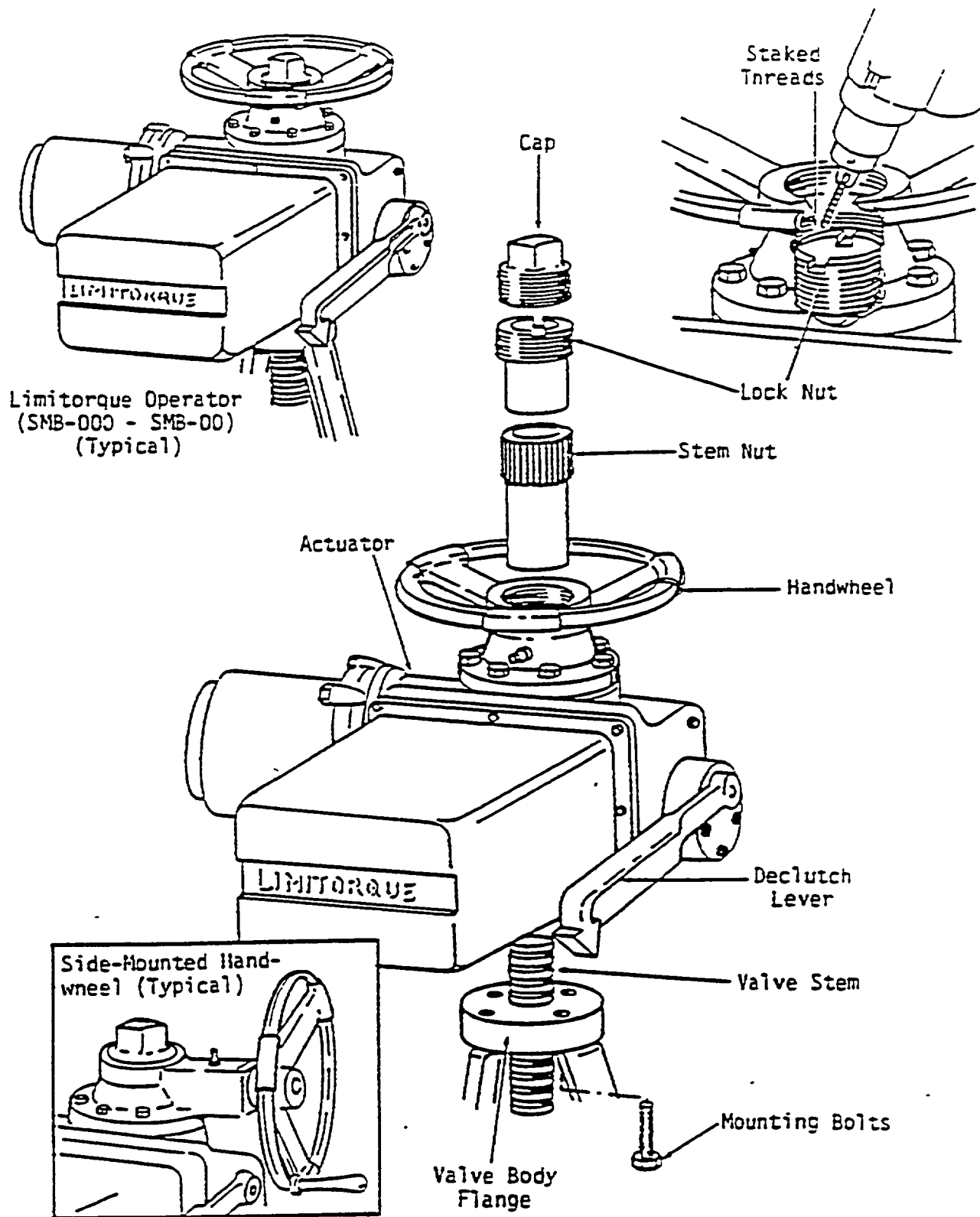


Figure 10-33. SMB-000/00 Limitorque Operator

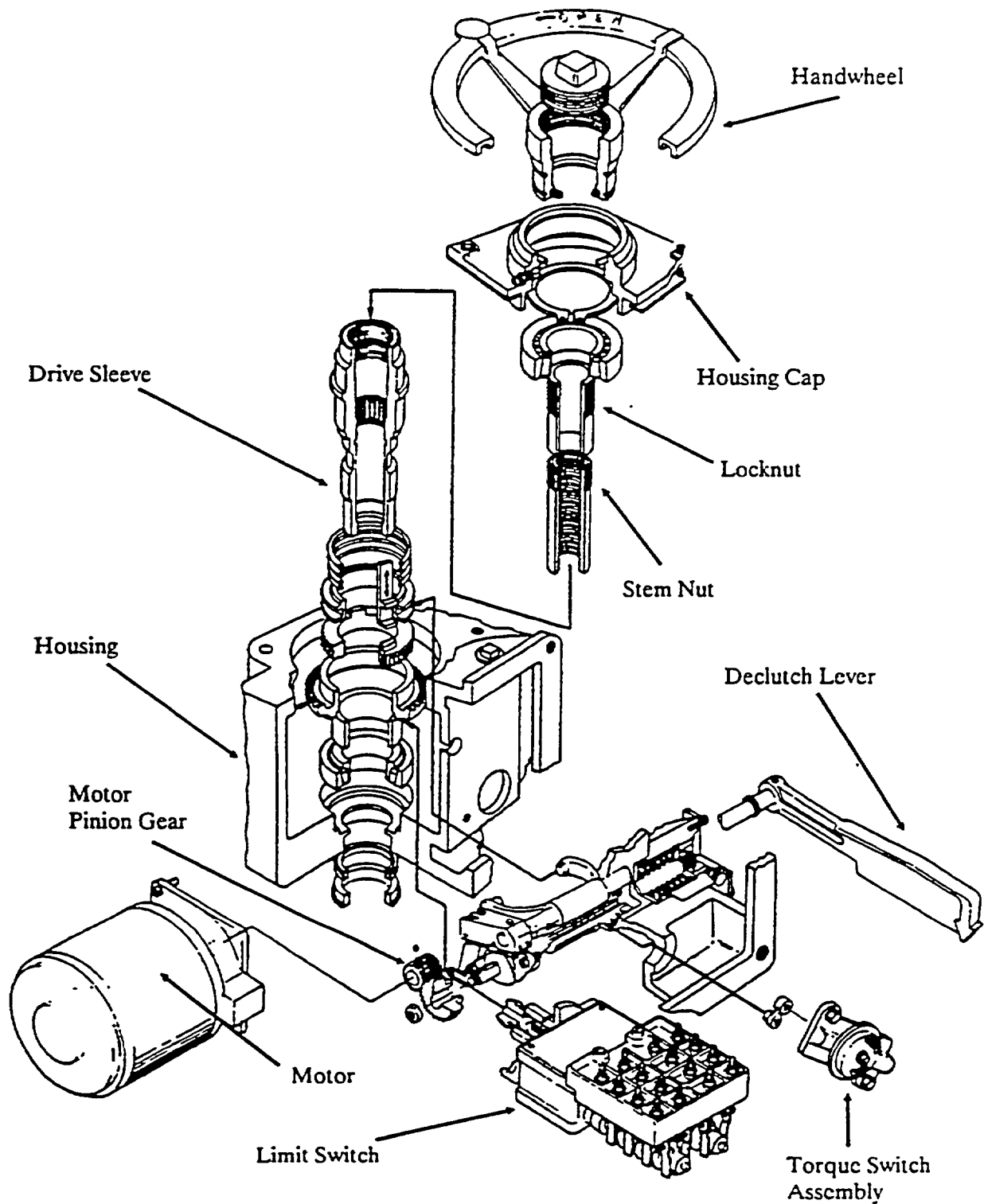
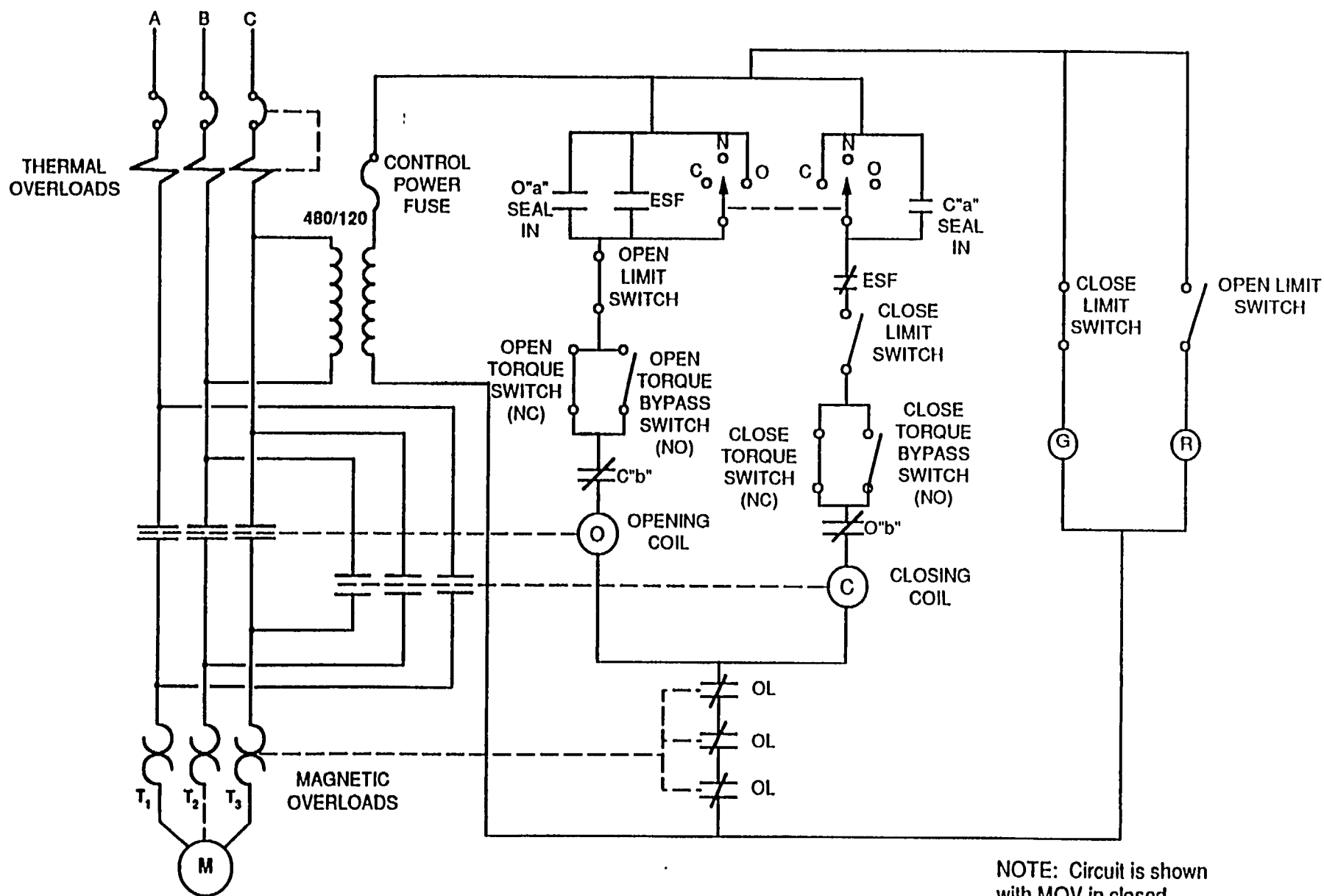
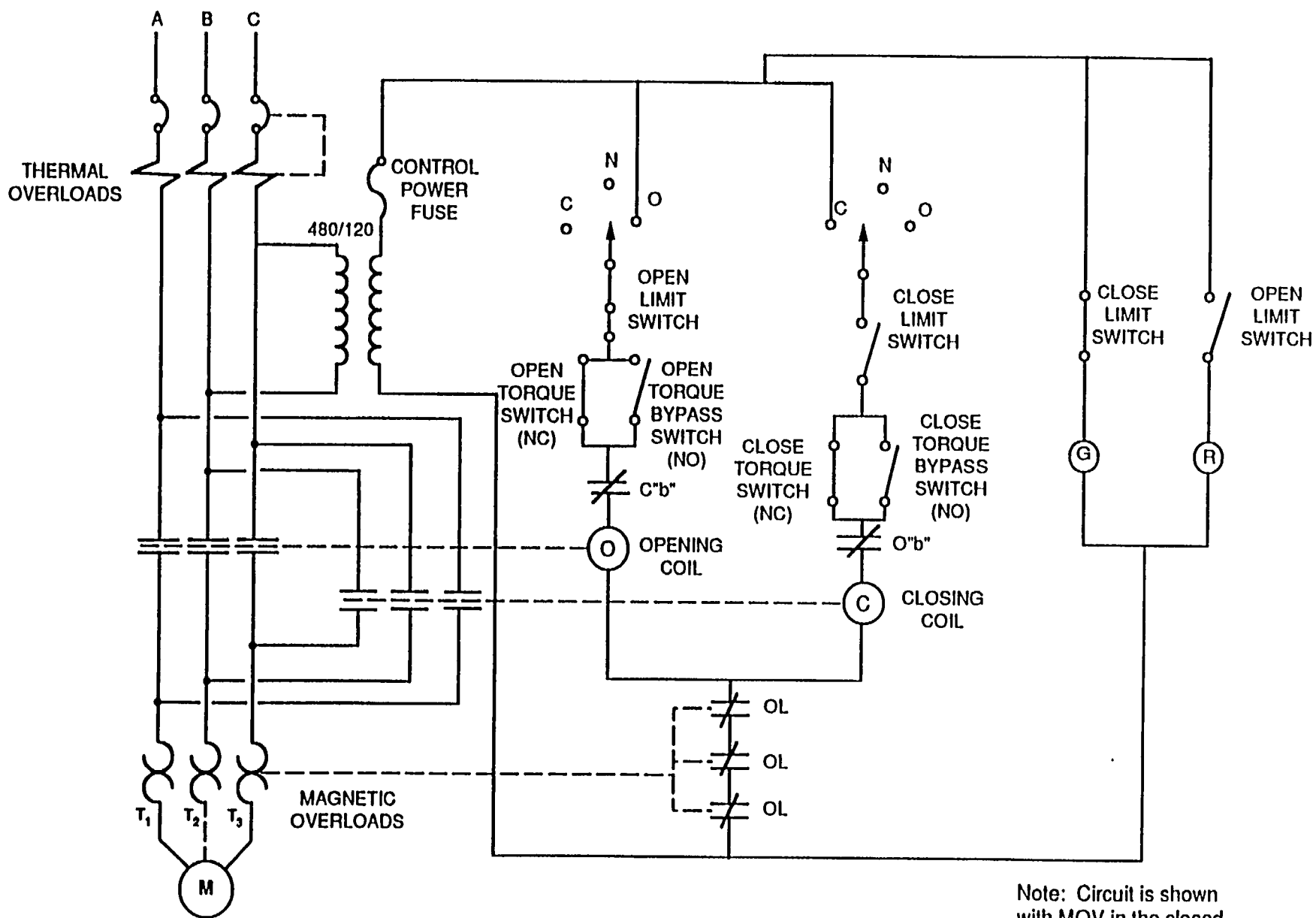


Figure 10-34. SMB-000 Limitorque Operator (Exploded View)



NOTE: Circuit is shown with MOV in closed position

Figure 10-35. Basic MOV Valve Control Circuit with Seal-in



Note: Circuit is shown with MOV in the closed position.

Figure 10-36. Basic MOV Throttle Valve Control Circuit

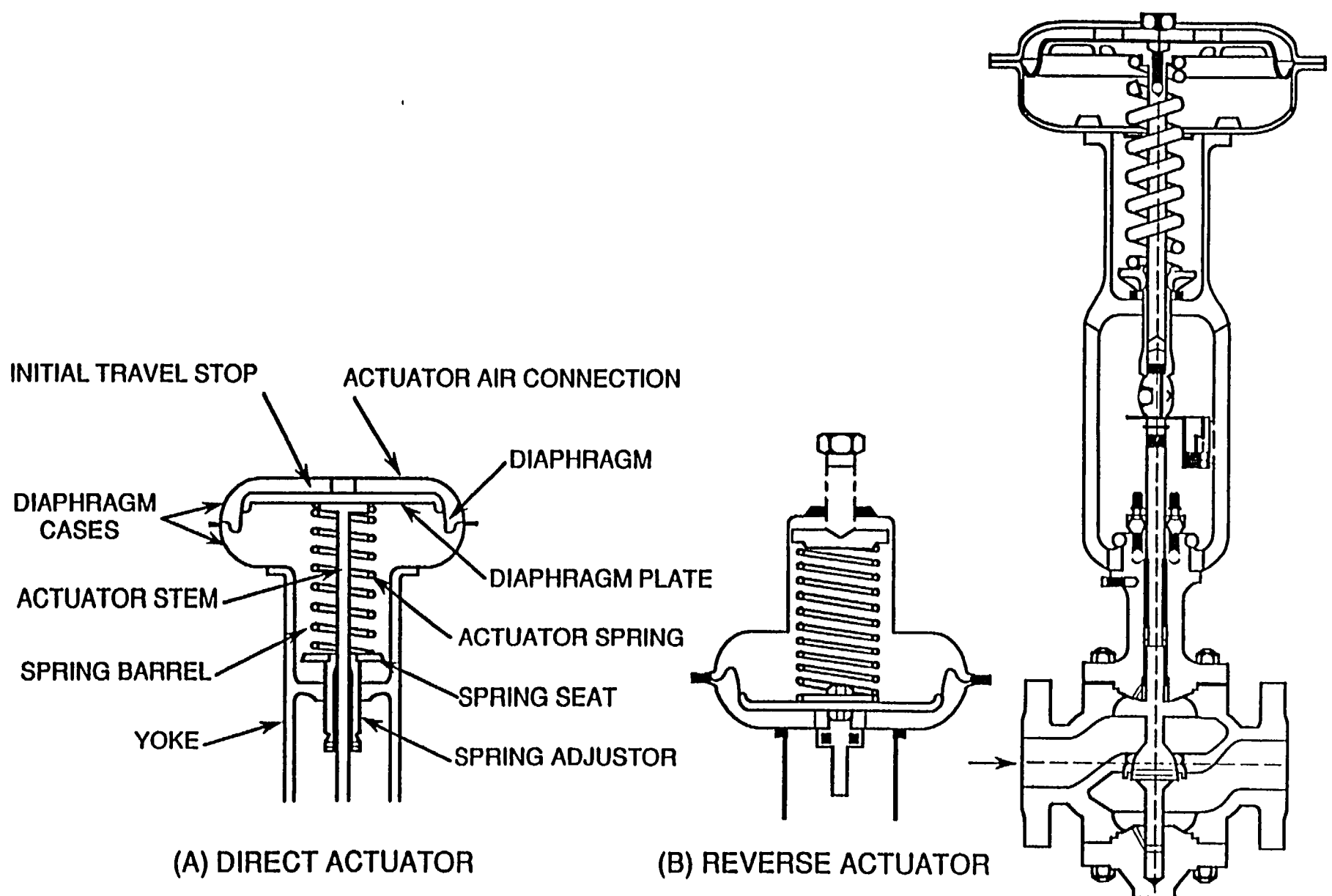


Figure 10-37. Diaphragm Operators

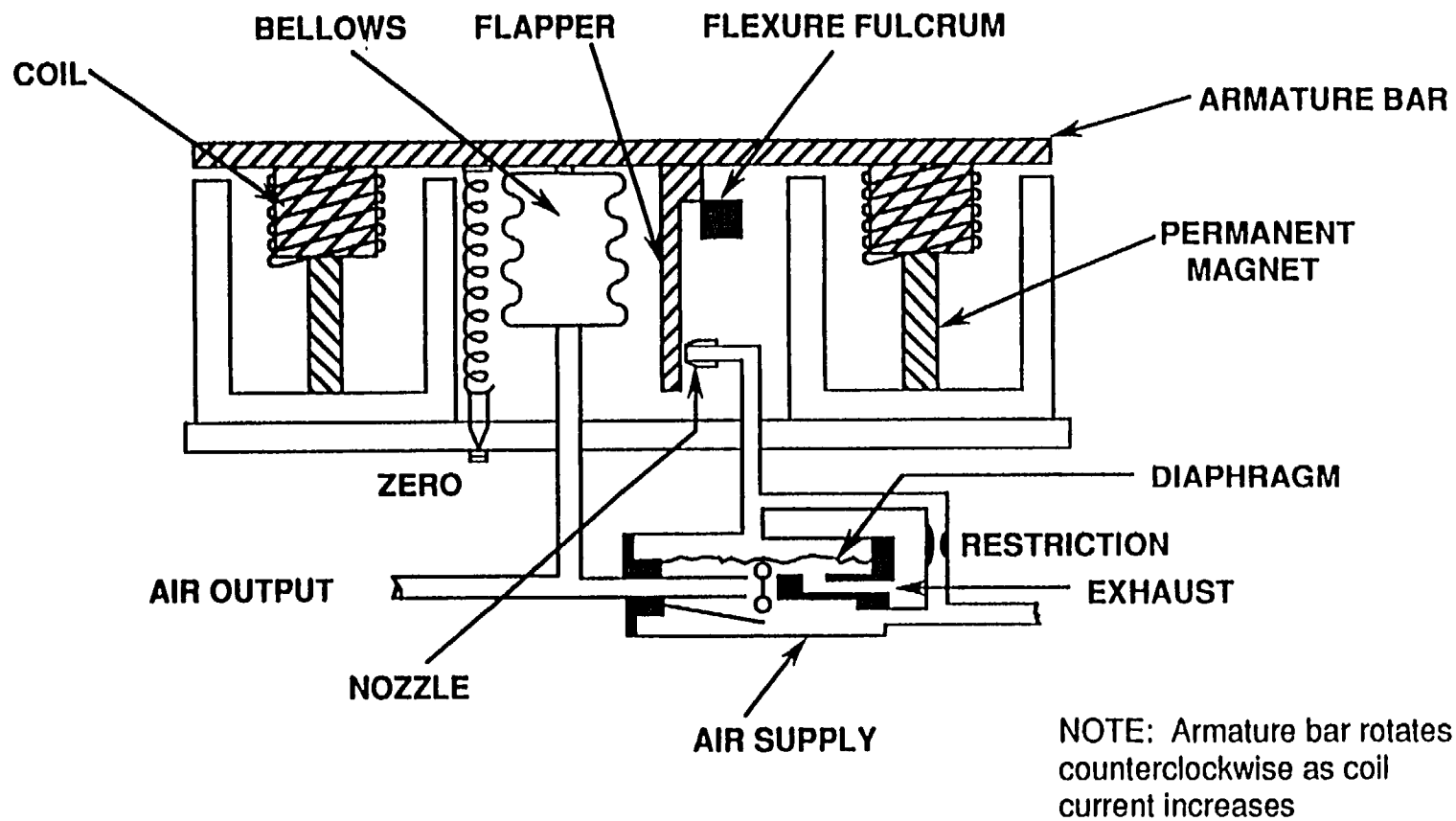


Figure 10-38. Simple E/P Converter

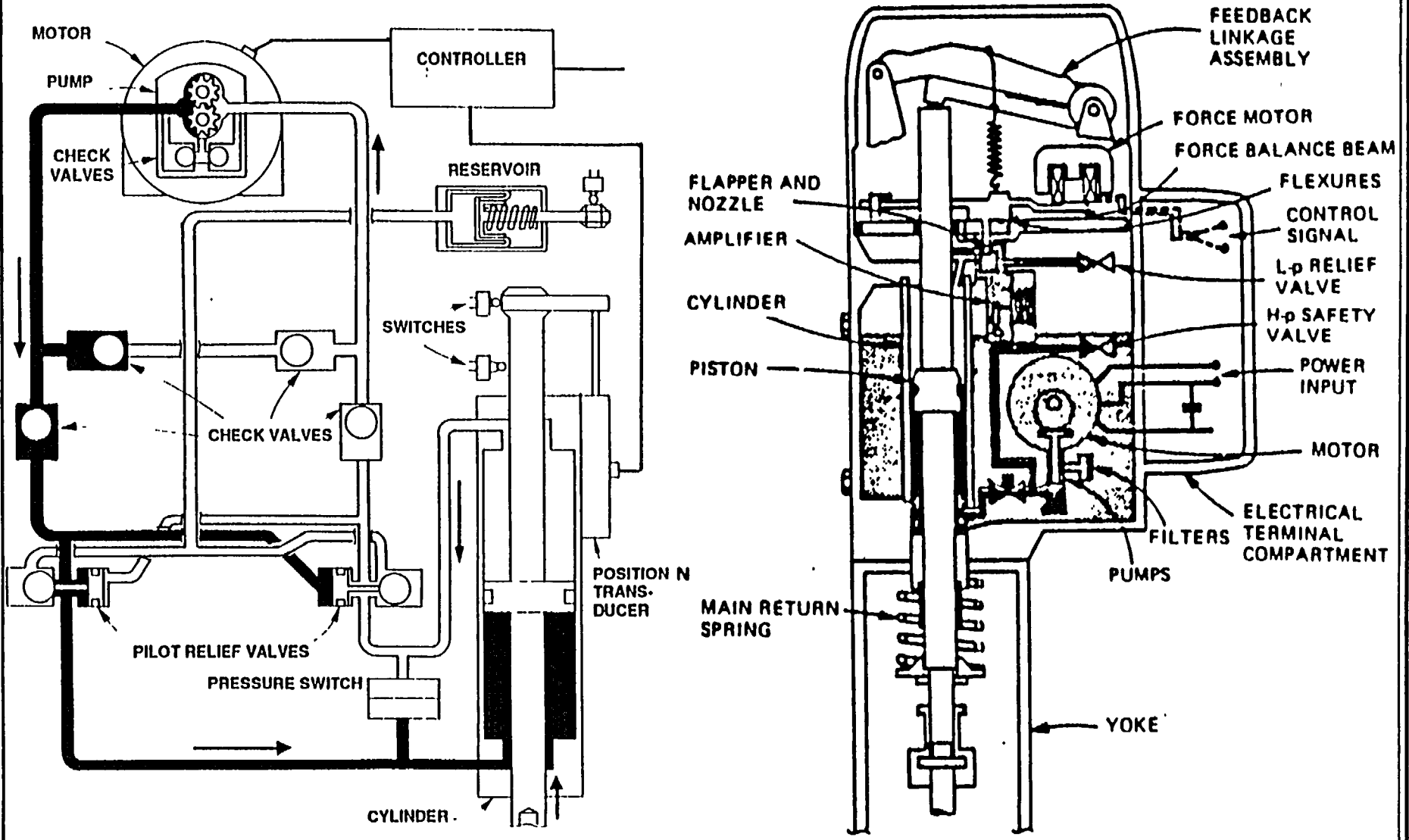


Figure 10-39. Hydraulic Operators

11.0 TURBINES

Learning Objectives

After studying this chapter, you should be able to:

1. State the purpose of a turbine.
2. Define or describe the following as appropriate:
 - a. Stop valve
 - b. Control valve
 - c. Combined intermediate valve (includes reheat stop valve and intercept valve)
 - d. Extraction nonreturn valve
 - e. Governor
 - f. Front standard
 - g. Critical speed
 - h. Journal bearing
 - i. Thrust bearing
 - j. Labyrinth seal
3. Explain the purpose of the following turbine auxiliary systems/components:
 - a. Moisture separator/reheater
 - b. Lubricating oil system
 - c. Turning gear and lift pumps
 - d. Gland seal steam system
4. Explain why a turbine is tripped under the following conditions:
 - a. High vibration
 - b. Overspeed
 - c. Low lube oil pressure
 - d. High thrust bearing wear
 - e. Reactor trip
 - f. High reactor vessel (steam generator) level
5. Explain how the addition of water to a Terry turbine can lead to turbine overspeed.

11.1 Introduction

The nuclear power plant utilizes saturated steam for transporting the thermal energy produced by

the reactor to the turbine generator where the energy is converted to mechanical energy. (Note: The Babcock & Wilcox and high-temperature gas reactor designs use slightly superheated steam.) The mechanical energy of the turbine is converted to electrical energy by the generator attached to the main turbine shaft. Other steam turbines are used to provide the motive power for main and auxiliary feed pumps, reactor core isolation cooling pumps, etc.

The admission of steam to a turbine is controlled by governing valves and quick-acting stop valves that will trip shut in an emergency.

The basic function of a steam turbine is to convert the stored thermal energy of steam into mechanical work. This is accomplished by the expansion of the steam through stationary nozzle vanes and rotating blades. The geometry of the nozzles and blades determines the pressure distribution throughout the turbine and also directs and turns the steam jets so that the forces on the blades develop a torque on the shaft.

11.2 Turbine Design Types

A turbine can convert thermal energy to mechanical rotation in two ways: by using the impulse force of the steam or by using the reaction force of the steam. Most turbines use both of these forces. In fact, both are frequently used in the same stage of a turbine. For descriptive purposes, they are presented here as separate major turbine types.

11.2.1 Impulse Turbines

Figure 11-1 shows the operating principle of an impulse turbine. Steam enters an impulse turbine through a stationary nozzle that expands the steam and creates a steam jet. The steam jet strikes the rotor blades, forcing them to rotate.

A pure impulse stage of a turbine is one where the entire pressure drop of the stage occurs across the stationary blades and no pressure drop occurs

in the rotating buckets (see Figure 11-2A). Thus, the acceleration of the steam (and the attendant pressure drop) takes place entirely in the stationary row or nozzle. The nozzles, arranged in a ring at one side to clear the moving blades, direct steam at an angle to the moving buckets. The crescent-shaped, moving buckets permit free entry/exit and change the speed/direction of the steam, which gives the rotational force. The steam expansion (pressure drop) occurs only in the nozzles, and pressure remains essentially constant in the moving buckets. The velocity rises in the nozzles but falls in the buckets.

A force is exerted in changing either the speed or direction of a body in motion, and the amount of force depends on the extent to which speed or direction is changed. For this reason, and because all of the pressure drop occurs across the stationary row in a pure impulse stage, the steam velocity leaving the stationary row is quite high, generally twice that of the bucket speed. In addition, because the change in direction is important in the impulse bucket to optimize the energy conversion, the turning angle is quite large. In the impulse stage, the kinetic energy of the steam is imparted to the rotating buckets, as evidenced by the reduced steam energy in the form of reduced velocity of the steam as it passes through the moving buckets.

11.2.2 Reaction Turbines

In the impulse stage described in section 11.2.1, the energy imparted to the moving buckets took the form of reduced velocity of the steam. Another form of energy extraction is accomplished by a reaction turbine or stage by the reactive force of steam expanding from a nozzle (see Figure 11-3).

In this design, energy is extracted from the steam when the moving blades absorb the reactive or jet thrust of the steam exiting the nozzle-shaped moving blades. The energy given up by the steam to the moving nozzles shows up as a decrease in the steam velocity and pressure (see Figure 11-2B). In an ideal reaction turbine, the moving

blades would be the only nozzles. This is impractical in large turbines because it is difficult to admit steam to moving blades without using some form of guiding nozzles or blades. For this reason, most so-called "reaction" turbines are in reality using both impulse and reaction principles.

Figures 11-2A and 11-2B show the steam pressure and velocity profiles of ideal impulse and reaction turbines. Note that the "reaction" turbine shows some of the characteristics of the "impulse" design because the fixed nozzles direct the steam so as to impart some change-of-direction force on the moving blades. The "reaction" turbine of Figure 11-2B in actuality also employs some impulse effect. Although it is possible to have a pure "impulse" turbine, there are no pure "reaction" turbines. Reaction turbines are so designated to distinguish them from pure impulse turbines.

11.3 Turbine Staging

Regardless of the type of turbine, multiple stages must be used to extract the maximum energy from the steam. The stage design may be impulse, reaction, or combined-type stages. For simplification, multiple staging will be discussed first as "pure" impulse and "pure" reaction.

11.3.1 Impulse Turbine Compounding

The steam supplied to a typical nuclear plant turbine-generator is saturated steam at approximately 1000 lb/in². It leaves the turbine at a vacuum, which represents an enthalpy change of approximately 400 BTU/lbm across the turbine. An impulse stage is capable of extracting approximately 40 BTU/lbm. This implies that 10 or more stages would be required to extract all the available energy. (Actually more than 10 would be needed because the efficiency of each succeeding stage decreases as the velocity of the steam decreases, and the 40 BTU/lbm value per stage is subsequently lowered.) There are two ways of extracting more energy — velocity compounding and pressure compounding.

The velocity-compounded turbine was designed and patented by C. G. Curtis, and a turbine stage using his design is generally known as a Curtis stage. Essentially a Curtis stage makes use of higher nozzle velocities than are possible in a straight impulse turbine because the Curtis stage absorbs the kinetic energy of the jet in more than one row of moving buckets. There are stationary blades between the rows of buckets whose sole function is to redirect the flow to the next row of buckets. For the ideal turbine, there is no pressure drop over either the moving buckets or stationary blades. A pressure-velocity diagram for a Curtis stage is shown in Figure 11-4.

Curtis stages with up to four rows of moving buckets have been built. It is most common, however, to have only two rows because efficiency beyond two rows increases only marginally. For example, for a Curtis stage with four rows of moving buckets, the proportion of power absorbed by the moving rows of buckets varies in the proportion 7:5:3:1. That is, the last bucket absorbs only 1/16 of the total energy. Clearly, the point of diminishing returns is quickly reached. Note that although a Curtis stage may have more than one row of moving buckets, the group consisting of one nozzle, two to four rows of buckets, and one to three stationary turning vanes is one stage. More than one Curtis stage may be used in series.

The second way to use more rows of buckets is pressure compounding. In this arrangement, also known as the Rateau turbine, there are multiple nozzles, each followed by one row of moving buckets.

The total enthalpy drop is divided approximately equally among each of the stages. Each stage is designed essentially as a single-stage impulse turbine. The pressure-velocity diagram for a Rateau turbine is shown in Figure 11-5.

An additional advantage of the Rateau turbine is that, with proper design of downstream nozzles, some of the energy in the steam exhausting from

the stage may be recovered, or "carried over." Not all that energy can be recovered. Typical values of carryover range around 85%; thus about 15% is lost in each stage. There is, of course, no carryover for the last stage.

11.3.2 Reaction Turbine Compounding

Reaction turbines are compounded by simple multiple staging, with each stage consisting of a row of stationary blades or nozzles, followed by a row of moving blades or nozzles.

As was done for the impulse turbine, a discussion of the turbine efficiency in terms of blade speed vs. steam speed is useful. For the reaction principle, maximum efficiency occurs when blade speed is equal (and opposite in direction) to steam jet speed. This is twice the speed required for the impulse type. This implies that a reaction turbine would require many more stages than a comparable impulse turbine. Obviously, the greater the number of stages, the larger and more costly the machine. Practical reaction turbines will have about 150% more stages than an impulse turbine.

11.3.3 Stage Efficiencies in Practical Turbines

An efficiency based partly on the nozzle efficiency and partly on the bucket or blade efficiency, known as the diagram efficiency, may be defined to help qualify stage efficiency. It can be shown that the peak efficiency of the 50% reaction stage, often known as an element, is greater than that of an impulse stage. The relative efficiencies of the turbine types may be examined as functions of p , the ratio of wheel velocity to jet velocity, or enthalpy drop per stage (assuming constant wheel velocity) as shown in Figures 11-6A and 11-6B.

These figures show that, while the peak efficiency of the reaction element is better than either type of impulse turbine, it falls off very quickly as the enthalpy drops per stage increases. In comparison, although the Curtis stage has a relatively low efficiency, it maintains its efficiency better at higher enthalpy drops. Such high enthalpy drops

are common in the first stage of a multistage turbine. Thus, as mentioned earlier, it is common to see Curtis stages used in the first stage of a "reaction" turbine.

Conversely, although it is possible to design pure impulse turbines, this is seldom done except in small, single-stage, mechanical-drive turbines for which cost rather than efficiency is the prime consideration. Practical power utility impulse turbines generally use some degree of reaction in design. The degree of reaction in most turbines increases from the first to the last stage.

11.4 Construction Details

11.4.1 Stage Sealing

A principal difference between reaction and impulse turbines is the place where the pressure drop occurs. In the impulse turbine, essentially all the pressure drop occurs across the stationary nozzle; in the practical reaction turbine, the pressure drop is split more or less equally between the stationary nozzle and the moving bucket.

In any turbine, one design consideration is to ensure that as much of the steam as possible passes through the steam path, rather than leaking around it. It is obvious that, considering where the pressure drops occur, leakage control and sealing are different for impulse and reaction turbines.

In reaction turbines, there is a pressure drop across both the moving and stationary buckets; therefore, equal attention to leakage is necessary at the tips of the buckets and between the shaft and the diaphragm, which supports the buckets. Figure 11-7A shows that there are about the same number of teeth in the labyrinth packing at these two locations (1 and 2).

In the impulse turbine shown in Figure 11-7B, because most of the pressure drop is across the stationary diaphragm, there are many teeth in the shaft packing 1 and only abbreviated packing or "spill strips" at the bucket tips 2 and at the root of

the bucket 3 where there is little pressure drop. Note also that there is a hole 4 in the bucket wheel of the impulse turbine. This "balance" hole allows the steam that does leak past the labyrinth packing to pass on to the next stage. If the hole were not there, the leaking steam would build up pressure on that side of the bucket wheel, producing thrust and disturbing smooth flow through the buckets.

The construction used for impulse turbines is known as compartment construction, so called because the wheels run in what appear to be compartments separated by the diaphragms. The reaction construction is known as drum construction. This is because the diameter of the rotors in reaction turbines is generally greater than that for impulse turbines. The greater diameter is necessary because, while both impulse and reaction turbines for utility applications must run at the same rotational speed, the bucket velocity for the reaction turbine must be greater for optimum efficiency. This is accomplished by using the larger diameter rotor.

11.5 Axial Thrust Loading

Another major difference between the reaction and impulse designs is the axial thrust on the rotor. Considerable axial force is generated on the rotor of the reaction turbine because of the pressure differential across each row of moving blades. The impulse turbine, with very little pressure drop across its buckets, has comparatively low axial force on the rotor. A major design consideration in reaction turbines is how to deal with this thrust.

One simple, brute-force method of dealing with large thrust forces is simply to have a large thrust bearing. However, this is impractical in most cases because such a thrust bearing would simply be too large.

Although all turbines have thrust bearings that help keep the shaft from moving axially, another method to eliminate thrust in larger, more recent turbine designs is the double flow rotor shown in Figure 11-8. In this design, the flow is split into

two equal parts and passes in opposite directions through symmetrical, half-sized blading. The forces on the two groups of blading, F_A and F_B , are approximately equal and opposite, practically eliminating the thrust problem.

11.5.1 Rotor Designs

The rotors that contain the rotating blades or nozzles may be machined from a single forging as an integral part of the turbine shaft for smaller turbine units (see Figure 11-9A). Larger units have rotors that are separate disks or wheels shrunk and keyed on to the shaft (see Figure 11-9B).

The thermal and mechanical stresses involved in heat-expanding/shrink-fitting disks or wheels is avoided in the design in Figure 11-9C. This European design features forged hollow sections welded together. After heat treating and stress relieving, blade root slots are machined into the outer periphery.

The rotor shaft is supported by journal bearings at each end. A thrust bearing acting on a thrust collar keyed to the shaft maintains axial position. Low-speed electric turning gears will rotate the shaft when the turbine is shut down to prevent shaft bowing from either gravity acting on the heavy rotor, or from uneven heating or cooling.

11.5.2 Shaft Sealing System

At points where the rotor penetrates the outer cylinders, some means is needed to prevent leakage of air into or steam out of the cylinders. The glands, with their labyrinth-type seal rings and the gland sealing steam system, are designed to perform this function.

The system, shown in Figure 11-10, consists of individually controlled diaphragm-operated valves, relief valves, and a gland steam condenser.

The gland sealing steam is supplied from either the main steam system or from an auxiliary source during the starting cycle. The system

described is for a multiturbine design having a single high pressure turbine mounted on the same shaft with three low pressure turbines (typical of a 1200 megawatt nuclear unit).

11.5.3 Rotor Glands

The glands contain a number of labyrinth seal strips that encircle the rotor at the ends of each outer cylinder, clearing the rotor surface just enough to prevent contact during operation (see Figure 11-11). The labyrinth seals provide a torturous path along the rotor that inhibits the flow of steam or air. The labyrinth seals are formed when a set of teeth machined into the turbine rotor mesh with teeth in the turbine casing. The teeth do not contact each other, but rather they form a torturous winding path for any flow along the turbine rotor. Any steam or air leakage along the rotor is constrained to flow through the labyrinth seals, effectively slowing the movement of steam or air and reducing leakage around the rotor.

On starting the turbine, and at low loads, the pressure at the high pressure (HP) and low pressure (LP) exhaust is below atmospheric pressure. Therefore, the pressure at the inner side of the glands is also below atmospheric (in a vacuum). Under these conditions (see Figure 11-12A), sealing steam is supplied from the gland sealing system to chamber X on both the HP and LP turbine seals. The sealing steam leaks past the seals into the turbine exhaust on one side, and into chamber Y on the other. The leakage of steam and air is removed from chamber Y through a connection to the gland steam condenser.

As the turbine load increases, the HP turbine exhaust pressure increases. When the HP exhaust pressure equals chamber X pressure, a reversal in flow occurs across the inner seal ring (see Figure 11-12B). As HP turbine exhaust pressure increases, the reverse flow increases and the HP turbine gland is sealed by the flow coming from the HP turbine exhaust. At this point, steam also begins to flow from the HP turbine gland chamber X to the LP turbine gland chamber X. At high

loads; steam from the HP turbine glands provides all sealing steam to the LP glands; the gland seal pressure regulator then bypasses excess seal steam pressure to the condenser rather than providing steam to the sealing system.

11.5.4 Gland Steam Condenser

The gland steam condenser maintains a slightly subatmospheric pressure in the gland leakoff system at all times. This draws the leakage steam from the glands, condenses, and removes it. The gland steam condenser may also receive steam from the feed pump turbine gland seal and control valve and throttle-stop valve steam leakoff.

11.6 Practical Turbine Types

The discussion of turbines thus far has been oriented principally toward understanding the physics and thermodynamics of the single stage. The practical details of getting steam into and out of the turbine, support of the rotor and bearings, etc., have not been examined. Full understanding of turbines requires some knowledge of some of these practical details.

The varieties of turbine design and arrangement (beyond impulse and reaction differences) are seemingly endless. It would be impossible to cover all the combinations and permutations in the scope of this text. However, within the industry, there are characteristics by which these many variations may be classified and so described (see Figure 11-13).

11.6.1 Condensing vs. Noncondensing

The first characteristic to consider is whether or not the exhaust from a turbine is condensed or not. In some very old power plants the exhaust steam was simply vented to the atmosphere. Later the realization was made that the power plant cycle could be more efficient and water treatment problems could be minimized by condensing and reusing the condensed exhaust (condensate), as shown in Figure 11-13A.

In other instances, the steam exhausted from the turbine may be used in some process such as heating, as shown in Figure 11-13B. In some cases the turbine may be used simply as a pressure reducer. If the exhaust pressure of a noncondensing turbine is higher than atmospheric, the noncondensing unit is called a backpressure turbine.

11.6.2 Extraction vs. Nonextraction

Many multistage turbines are designed so that steam may be extracted, or bled, from the steam path at some point or points between the first and last stages. This steam may be used for some process such as heating or driving other smaller turbines. An added benefit of extraction is the concurrent removal of moisture. Some large turbines may have as many as six or eight extraction points. Figure 11-13C shows a turbine with three extraction points. Extraction turbines are also sometimes called bleeder units.

Extraction turbines may be further subdivided into simple and automatic extraction units. In normal operation the pressure at any point in a turbine, and thus any extraction point, is a function of load. In a simple extraction turbine, no effort is made to control the extraction pressure. In an automatic extraction turbine, valves are placed in line at the extraction points to control pressure. Pressure and/or flow control may be required for some processes. Figure 11-13C shows a triple automatic extraction condensing unit, Figure 11-13D a double automatic extraction noncondensing unit, and Figure 11-13E a single nonautomatic extraction condensing unit.

11.7 Reheat vs. Nonreheat

In some multistage units, all the steam is piped back to the boiler or a separate reheater after it passes through a portion of the turbine. The reheated steam is piped back to pass through the remaining turbine sections, as shown in Figure 11-13F. In some large units the steam may be piped back to the boiler to be reheated a second time.

These are called double reheat units (see Figure 11-13G). The advantage of reheating the steam is that it improves the Rankine efficiency of the power plant and delays the onset of saturation of the steam as it expands through the turbine.

11.7.1 Single Casing vs. Compound Turbines

Simple, small, multistage turbines are generally built with all the stages on a single shaft that runs in one casing. As turbine sizes increase beyond about 40 megawatts, it becomes impractical to use a single casing. The different stages may be split among two or more casings on separate shafts. As many as six different casings may be used.

If all the shafts of the different casings are bolted together in line to drive the same generator, this is called a tandem-compound turbine. In some other instances, the sections may be arranged with two shafts, or groups of shafts, side by side, driving two separate generators. This latter arrangement is called cross-compounding and is advantageous when it is easier to build two half-sized generators than one large one. Tandem-compound and cross-compound units are shown in Figures 11-13H and 11-13I, respectively.

11.7.2 Single vs. Multiple Flow

Another characteristic used to classify the turbines is the number of flows among which exhaust steam is divided. There is generally only one flow for a single casing unit. Compound turbines may have the exhaust flow divided among two, three, or up to six flows. This is generally accomplished by using double-flow, low pressure turbine sections. A tandem-compound, double-flow unit is shown in Figure 11-13J.

11.8 Modern Power Plant Turbines

Figure 11-14 shows a turbine-generator unit that could be utilized with either a BWR or a PWR reactor. The turbine consists of one HP and three dual exhaust LP turbines. It is an 1800 rpm,

tandem-compounded, six flow steam turbine. Figure 11-15 is a cross section of the same turbine unit showing steam inlets and exhaust from each of the four turbines. Steam flow can be traced through the turbine unit utilizing Figure 11-16.

Steam approaches the turbine unit from the main steam system through four main steam lines that are connected by an equalizing header just prior to the turbine unit. The steam flow is then through four lines to an inlet steam chest containing four stop valves (SV) and then four control valves (CV). Flow is then to the center of the HP turbine and the first stage of blades. Steam flow splits into two flow paths due to the double flow design of the HP turbine. This double flow design is used on both the HP and LP turbines to counteract the thrust of the steam flow through the turbine stages. The HP turbine casing is a horizontally split, single shell approximately 8 inches thick. This thickness imposes stringent heatup limits on the HP shell casing prior to rolling the turbine to rated rpm.

Steam is exhausted from the HP turbine through four lines. The steam that has passed through the HP turbine has provided approximately 70% of the total work accomplished by the turbine unit. However the steam has changed from pure saturated steam at the HP turbine inlet to steam carrying 20 to 24% moisture at the HP turbine exhaust. Flow is then directed to the moisture separator-reheaters where the moisture is removed and the steam is reheated by steam from the Main Steam System. This reduces blade erosion and efficiency losses due to moisture in the LP turbine.

Steam flow then divides into six flow paths and passes through the combined intermediate valves for entry to the center of the three LP double flow turbines. The LP turbines are of double shell construction, and due to the lower temperature of the steam, do not present an operation problem during heatup of the turbine unit. Steam is exhausted from each end of the LP turbine downward to the main condenser which is at a 28 in/Hg vacuum to improve turbine efficiency.

11.8.1 Turbine Valves

11.8.1.1 Stop Valves

As shown on Figure 11-16, four turbine stop valves are located in the main steam piping just upstream of the turbine control valves. These stop valves are normally open during turbine operation and are emergency valves which rapidly close to isolate the turbine steam supply for turbine protection. The four stop valves have a below the seat equalizing header common to all four. The number 2 stop valve has an internal bypass which is used to warm up the turbine prior to turbine startup. The stop valves are hydraulically opened against spring tension and can trip closed within 0.1 second.

11.8.1.2 Control Valves

The four turbine control valves (governor valves) are located between the turbine stop valves and the turbine. The control valves regulate the flow of steam to the turbine and control the turbine generator load.

The Electro Hydraulic Control (EHC) system for a BWR unit will moderate the control valves position to maintain a constant reactor pressure for a specific reactor power. This means the turbine output follows reactor power.

The EHC system for a PWR unit will moderate the control (governor) valves position to maintain a constant generator output. This means that the reactor output follows turbine load.

The turbine control valves also trip closed on a turbine trip due to spring tension.

11.8.1.3 Combined Intermediate Valves

The combined intermediate valves (CIVs) are located in the steam flow path just upstream of the LP turbine. These valves have two valve seats inside one valve body, on a GE turbine. Each valve can travel 100% of its stroke regardless of

the other valves position. The first part of the valve is the intermediate stop (reheat stop) valve. It is normally fully open and will trip close on a turbine trip. The second part of the valve is an intermediate control (intercept) valve. This valve is also normally fully open, but will modulate closed during a turbine overspeed condition.

11.8.2 Electro-hydraulic Control System

The EHC oil system is a separate high pressure (1600 psig) hydraulic system used to position the turbine valves as required by the EHC logic system. The EHC system uses specific plant parameters to regulate steam flow to the turbine during heatup, roll to rated rpm, and power generation. These parameters are different for the plant type. The EHC system also provides for testing of turbine valve operation and initiation of trip commands to the turbine steam valves.

The EHC hydraulic power unit, shown in Figure 11-17, provides high pressure hydraulic fluid, which is divided into several different oil supply paths to various steam valves.

The hydraulic power unit consists of a fluid reservoir, pumps, fluid coolers, strainers, filter, and accumulators. The pumps are motor driven, variable delivery, piston pumps. Normally one pump is running and the other is in standby. If the running pump fails, the standby pumps will automatically start when system pressure decays. The hydraulic drain lines from the various steam valves are routed through tube and shell coolers, which are cooled by the Turbine Building Cooling Water (TBCW) system.

11.8.3 Lube Oil System

The main turbine lube oil system, shown in Figure 11-18, provides lubricating oil to the bearings of the turbine and generator during startup, shutdown, and normal operation. It also provides lube oil to the overspeed and mechanical trip devices, to the thrust bearings, and to the thrust bearing wear detector.

The main turbine lube oil arrangement consists of a turbine lube oil tank, five oil pumps, two lube oil coolers, a vapor extractor, oil mist eliminator, ten turbine shaft lift pumps, and associated strainers, piping, and instrumentation.

During turbine startup and coastdown, the turbine shaft lift pumps supply pressurized oil to lift the main turbine shaft off the lower bearings surface. This helps to reduce the turning gear torque requirements and to protect the bearings at low turbine speeds by preventing metal to metal contact.

The turbine lube oil tank, which provides the mounting structure for the turbine lube oil coolers, motor suction oil pump, turning gear oil pump, emergency bearing oil pump, and vapor extractor, is supplied oil from and discharges oil to the turbine lube oil storage and conditioning system. During normal operation of the main turbine, only one lube oil cooler is in service with the other maintained in a standby condition.

The main shaft oil pump, which supplies oil to the bearings of the turbine generator shaft, is a centrifugal pump mounted on the turbine shaft. It is supplied with suction oil by the oil driven booster pump located in the turbine lube oil tank. Oil discharging from the main shaft oil pump is piped to the lube oil tank where it passes through an oil driven turbine which drives the oil driven booster pump. In passing through the oil turbine, the oil pressure is reduced while providing power to drive the oil driven booster pump.

The oil then proceeds through the turbine lube oil cooler and on to the bearing. The oil driven booster pump has the advantage of not adding any power requirements to the system, while accomplishing oil pressure reduction for turbine bearing use. This allows a more efficient use of the oil system.

Two motor driven centrifugal oil pumps are provided to supply bearing oil to the turbine bearings while the turbine is on the turning gear,

coming up to speed, coasting down to stop, or in an emergency condition. These pumps are the turning gear oil pump, which is AC powered, and the emergency bearing oil pump, which is DC powered. They take oil directly from the lube oil tank and discharge it into the bearing header prior to the turbine lube oil coolers. The motor suction oil pump is an AC motor driven centrifugal oil pump that performs the function of the oil driven booster pump until the turbine shaft has reached approximately 95% of rated speed. High pressure operating oil is not available to drive the oil driven booster pump until the main shaft oil pump has reached about 95% of rated speed (1800 rpm). Thus, until this speed is attained, the function of the oil driven booster pump (to provide the main shaft oil pump with suction oil at a positive pressure), must be provided by the motor suction oil pump.

11.8.4 Turbine Bearings

11.8.4.1 Main Bearings

Journal bearings are provided at both ends of each turbine and both ends of the generator and exciter for support of the main shaft's weight and full lateral alignment inside the turbine and generator casings.

Figure 11-19 illustrates various views of a journal bearing. It consists of a cast steel shell lined with babbitt and provided with means for lubrication and for vertical and horizontal adjustment of the position of the bearing axis. The shell is split and bolted at the horizontal joint. Two dowels ensure perfect alignment of the two halves, when assembled.

The bearing is carried in a support ring consisting of two halves, which has a spherically bored seat that is machined to a slightly larger radius than the outer spherical surface of the bearing. This allows the bearing to move inside the support ring, enabling the bearing to align itself to the journal. The bearing is prevented from rotating by a pin that has ample clearance in the upper support item

so as not to restrict the self-aligning capabilities of the bearing.

Oil is supplied to the bearing through a flange bolted to the upper support and into the upper half of the bearing. The oil enters the bearing in the relieved section that does not extend to the ends of the bearing but stops inside of an annular groove at each end. From these grooves, the oil passes to drain through the holes in the bottom half of the bearing. This arrangement ensures a positive supply of oil for the journal lubrication at all times.

11.8.4.2 Thrust Bearing

One thrust bearing is provided (see Figure 11-20) for the turbine-generator unit and is usually located near a LP turbine casing. Even though the turbine is designed for a balanced thrust due to balanced extraction points and double flow design, there will be thrust experienced by the rotor during changing steam or load conditions.

The thrust of the rotor is transmitted to the shoes by the collar machined integrally with the turbine rotor shaft. A full complement of shoes is provided on each side of the thrust collar to carry the thrust in either direction.

The thrust bearing is of the leveling plate type, which automatically distributes the load equally on the shoes. These shoes are supported on the leveling plates, which are carried in the retaining ring. The leveling plates, by means of their rocking motion, allow the shoes to take a position so that the center of loading of the babbitt faces are all in the same plane.

Consequently, each shoe takes an equal share of the load. This construction eliminates the necessity of having all the shoes exactly of the same thickness. By accumulative shifting of the leveling plates, the thrust shoe load is also uniformly distributed if the shaft carrying the collar is not exactly parallel to the bore of the housing.

The thrust bearing is flooded with oil under pressure at all times. The oil is supplied directly from the bearing oil line through two connections in the upper half of the thrust bearing cage. As the thrust collar rotates with reference to the shoes, the film of oil between each shoe and the loaded collar will tend to take a wedge-shape with the thick side of the wedge on the forward or entering edge of the shoes. Thus, the oil is carried between the bearing surfaces by the motion of the collar and assures proper lubrication.

11.8.5 Extraction Steam

Extraction steam provides the heat source for heating up the feedwater to approximately 400°F prior to entry into the reactor or steam generators. This heating is provided in tube and shell feedwater heaters that pass feedwater inside tubes that are heated from outside by the extraction steam. There are usually six different pressure ranges of feedwater heaters. The higher pressure heaters receive extraction steam from the HP turbine and the lower pressure heaters receive extraction steam from the LP turbines. Because the steam pressure decreases with passage through each turbine stage, each set of feedwater heaters will have a progressively lower pressure. For each feedwater heater pressure, there are usually two or three parallel flow paths for the feedwater; therefore, two or three feedwater heaters are operating at that pressure.

The extraction steam lines to the feedwater heaters are equipped with extraction nonreturn (ENR) valves that automatically close on a trip of the main turbine or on high water level in the heater. The ENR valves prevent backflow of water or steam from entering the turbine and causing damage either by water induction or by turbine overspeed as a result of reverse steam flow. The ENR valves may be either air-operated check valves or a combination of an air or motor-operated isolation valve with a simple swing check valve, depending on the design of the particular system.

Because the lowest pressure heaters are located within the condenser, their extraction lines have no shutoff or check valves to isolate the heaters. The extraction steam piping to these heaters is protected from water induction by the automatic closing of the heater condensate inlet and outlet valves when high heater level is detected.

11.8.6 Exhaust Hood Spray

Steam not only supplies the energy to move the turbine blades, but also provides a means to remove frictional heat from the turbine blades. At low steam flow rates, the last stages of the low pressure turbine can heat up causing the exhaust hood temperature to rise an excessive amount. To cool the exhaust hood, an exhaust hood spray system automatically controls the temperature by spraying cool water on the hood (not onto the rotating blades) and removes some of this heat. The turbine generator should not be operated at low loads (less than 5%) for any long period of time to prevent damage to the last stage buckets.

11.8.7 Turning Gear

The motor driven turning gear shown in Figure 11-21 is used when the turbine is shutdown and still hot. The turning gear motor turns the turbine shaft at 1 to 2 rpm to prevent shaft bowing due to weight or differences in thermal expansion. Even though the turning gear is not needed when the turbine is $\leq 200^{\circ}\text{F}$, the turbine is usually left on the turning gear for the duration of the shutdown, except during times of turbine maintenance.

11.8.8 Front Standard

The front standard, as the name implies, is located at the front end of the HP turbine. Its main function is to support the HP shell and the HP rotor. The front standard can be pictured most simply as a large metal box that slides. At the rear of the front standard is the number one bearing that supports the HP rotor. The rear of the front standard, along with the mid standard, also sup-

ports the weight of the HP turbine shell.

In addition to providing structural support for the HP turbine, the front standard also houses various devices and control components. These include, but are not limited to:

Control Devices

- Overspeed trip,
- Mechanical trip valve,
- Lockout valve,
- Oil trip valve,
- Mechanical trip solenoid,
- Low speed switch, and
- Mechanical manual trip.

Other Devices

- Shaft grounding devices,
- Oil sights,
- Main oil pump, and
- Speed sensing head.

11.8.9 Turbine Governor

The function of the turbine governor is to control steam flow through the turbine to maintain shaft speed constant under varying load conditions. Although there are many types of governor systems, all are fundamentally the same. All governors have a device which will sense turbine rotor speed and will open the throttle valve when it senses turbine speed decreasing and will shut the throttle valve when it senses turbine speed increasing.

The simplest type of governor system is the flyweight governor (see Figure 11-22A). This system uses two flyweights that are connected to the turbine rotor speed. As the rotor and flyweights spin faster, centrifugal force pushes the flyweights outward. This causes the flyweights to pivot about their fulcrum, lifting the speeder rod up against the speeder spring force. As shown in Figure 11-22B, when the speeder rod is lifted, it pivots the steam control valve lever causing the control (throttle)

valve to close, thereby reducing steam flow to the turbine. The same logic applies to the case where turbine speed decreases. As the turbine rotor slows, the flyweights move inward, forcing the speeder rod downward. This action lifts the control valve, letting more steam into the turbine and increasing turbine speed. Most large turbines use a hydraulic governor system. This system uses an oil pump and oil pressure to measure turbine speed rather than flyweights and mechanical linkages, but the concept of operation is the same.

11.9 Turbine Operational Problems

The principal troubles arising in steam-turbine operation that must be guarded against are (1) unequal expansion of different parts during startup, (2) water in the casing, (3) overspeeding, and (4) vibration. A peculiar fact is that nearly all troubles experienced with steam turbine, except overspeeding, will manifest sooner or later as vibrations. Hence, the chief duties of a turbine operator, while a turbine is in operation, are to carefully guard against overspeeding and vibrations.

11.9.1 Vibration

As already stated, turbine vibration is a major concern to the turbine operator. Listed below are several causes of turbine vibration and the probable reason for the problem. Most problems require a turbine shutdown and maintenance to solve the cause of the vibration.

Cause	Probable Reason
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Unbalanced	Sprung Shaft
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	Improperly placed balance weights
--	-----------------------------------

	Displacement of balance weights
--	---------------------------------

	Sediment in blades or buckets
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Corroded blades

Unequal heating of rotor parts

Unbalanced forces due to heavy distortional stresses

Shifting of conductors or generator

Unequal generator air gaps

Poor Alignment	Eccentric coupling
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	Unequal settling of foundation
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	Steam-piping strains due to expansion or weight
--	---

Bad Foundation	Improper grouting
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	Nonrigid fastening of bedplate
--	--------------------------------

	Nonhomogeneous foundation resulting in unequal settling
--	---

Loose Parts	Too much bearing clearance
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	Ball joint of bearing loose
--	-----------------------------

	Loose construction in built up rotor
--	--------------------------------------

	Loose coupling or bolts
--	-------------------------

Internal Rubbing	Revolving buckets coming in contact with stationary buckets
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	Insufficient casing clearance
--	-------------------------------

	Deflection of a diaphragm or disc in one stage
--	--

	Thrust-bearing troubles
Steam Troubles	Water coming over with the steam
	Sediment in the steam
	Faulty valve gear causing irregular steam admission
	Accidental closing of emergency steam valve shifting generator's load to other machines
Packing Troubles	Improper adjustment of labyrinth packing
	Packing rings too small for shaft
Oil Troubles	Breaking down of oil film due to insufficient supply
	Oil supply cut off or too slow
	Poor oil (frothing, gumming, emulsifying)

11.9.2 Critical Speeds

Critical speed is a physical characteristic of all rotating shafts. The critical speed of any rotor depends on its geometry, material, and size. The vibration of a shaft at critical speed may be much greater than the vibration of the same shaft above and below the critical speed (see Figure 11-23).

Any body having weight and "springiness" has one or more natural frequencies at which it can vibrate. If forces are applied to the body at any of these natural frequencies, a resonance condition will build up, and the amplitude of motion will become quite large. Because a machine shaft has weight and deflects under load, it has several

natural frequencies. It is difficult to balance a shaft perfectly so that during rotation centrifugal forces are set up within it that act on the shaft at the same frequency as the shaft rotates. If this impressed frequency coincides with a natural frequency of the shaft, resonance occurs. This speed of rotation is then known as a critical speed.

Resonance is an undesirable condition because it may cause parts to rub and creates high shaft stresses. Consequently, the running speed is kept at least 20% away from the critical speed. Because the shaft has a number of natural frequencies, it also has a number of critical speeds. For most actual machinery shafts, only the first or second critical speed is of importance.

As shown in Figure 11-23, rotors have more than one critical speed. In general, turbine generators operate well below the turbine rotor's third critical speed and just above the generator rotor's second critical speed.

When starting or stopping a turbine, it is important to pass through the critical speeds without unnecessary delay (in a few seconds). Excessive vibration will usually not be a problem if critical speeds are passed rapidly. If the unit is held at a critical speed for too long, excessive vibration and rubbing can occur.

If there is excessive vibration at a critical speed while the unit is slowing after a trip, the operator may open the vacuum breakers. This will open the condenser to the atmosphere, increasing the pressure in the condenser and later stages of the turbine, which will cause the turbine to slow more quickly.

However, vacuum should not be broken at greater than two-thirds rated speed (1200 rpm for a 1800 rpm unit) unless vibration is extreme because breaking vacuum at higher speeds can damage LP turbine buckets because of aerodynamic (windage) heating.

In addition, during shutdown and startup, the

unit should not be operated for a significant amount of time below its first critical speed. The manufacturer will place a maximum time on operating in this condition. Rubbing and bowing may be the result of such operation. Note that an exception is when the unit is on the turning gear.

11.9.3 Water Induction

Experience has demonstrated that serious damage can occur in steam turbines as a result of water entering any of the various openings in the shells while the turbine is hot and running or hot and shutdown on turning gear. Such operation can result in overstressed and humped casings, damaged buckets, badly rubbed internal parts, and even permanently bowed rotors.

11.9.3.1 Extraction Lines

Extraction lines represent the most frequent source of water involved in turbine mishaps. Water from high and intermediate pressure extraction lines can cause serious quenching of hot turbine sections and from the low pressure lines can cause damage to LP turbine buckets. Water induction involving extraction lines can usually be attributed to one of the following causes:

- Leaking feedwater heater tubes,
- Feedwater heater level controls that malfunction or are not adequate for some transient condition,
- Improper drain systems such as drain manifolds that choke and restrict flow,
- Leakage or misoperation of the ENR valves in the extraction lines to feedwater heaters, or
- Leakage or misoperation of valves where extraction lines are interconnected with such sources of steam as startup steam for boiler feed pump turbines or deaeration.

11.9.3.2 Steam Seal System

The steam seal header has a continuous drain from its lowest point to the condenser to prevent a gradual accumulation of water from flooding the header and entering the turbine. This drain can become plugged, and in any case, is not sufficient to pass large quantities of water if admitted into the steam seal system.

11.9.3.3 High Reactor Vessel/Steam Generator Water Level

If the water level in the reactor vessel of a boiling water reactor or the steam generator of a pressurized water reactor is too high, moisture droplets could become entrained in the steam and could be carried over into the turbine. High moisture content steam can cause turbine blade erosion, or in some cases, catastrophic failure of the turbine blading. To prevent turbine damage, the turbine is tripped when reactor vessel/steam generator water level becomes too high.

11.9.4 Overspeed

If the generator circuit breaker is opened while the turbine is producing power, turbine-generator speed will increase. This is because only 2% of rated steam flow is required to maintain the turbine at rated rpm. Any steam flow above this amount is used to add torque to the turbine shaft and produce electrical power.

Closure of the turbine valves and nonreturn valves associated with extractions, flash tanks, etc., will close off sources of energy external to the turbine, the turbine will cease producing power, and the speed increase will be limited to design values (assuming no abnormal energy source such as excessive water in a hot steam path). But failure-to-close of certain combinations of the valves mentioned above or excessive water in a hot steam path can result in the turbine continuing to produce power with the result that the turbine-generator speed will continue to rise.

During this time the turbine control system (EHC) will close the turbine control valves (100 to 105% rated rpm) and the turbine intermediate control valves (105 to 107% rated rpm). If these control measures fail, there are two separate trip devices at approximately 110% of rated rpm.

11.9.5 Low Lube Oil Pressure/High Thrust Bearing Wear

Commercial nuclear plant steam turbines normally operate at 1800 rpm; therefore, adequate lubrication of the various bearing surfaces is critically important. Loss of bearing lubrication, even for a short period of time, can completely destroy a bearing surface. To prevent bearing damage, the turbine is immediately tripped when there are indications of low oil system pressure.

High thrust bearing wear is also an indication of a malfunction of the lubricating oil system. When high thrust bearing wear is indicated, the turbine is tripped as a precautionary measure until the cause of the excessive wear can be identified.

11.9.6 Reactor Trip

PWR plants automatically trip the turbine when the reactor trips. This is done to prevent the rapid cooldown of the reactor coolant system. When the reactor trips, most heat generation in the core stops. If the secondary steam system continues to remove heat from the primary system via the steam generator and the steam turbine, the primary system will rapidly cool down. This cooldown could cause high thermal stresses which could adversely effect the integrity of the reactor vessel. The cooldown would also add positive reactivity, which could cause an inadvertent reactor restart if it were allowed to continue too long.

11.10 Standby Auxiliary Turbines

Both BWRs and PWRs have a need for auxiliary feedwater supplies under specific plant conditions. These auxiliary feedwater pumps for a PWR or reactor core isolation cooling system

pumps for a BWR utilize turbine driven pumps. These pumps are normally not operating, but must be capable of startup and obtaining rated flow in ≤ 25 seconds. This requires a turbine with larger clearances than the main turbine, thus not requiring any pre-heating before operation.

The nuclear industry utilizes an impulse re-entry turbine of the axial-flow type made by the Terry Turbine Company. This type of blading can best be described as water wheel type of blading. This type of blading can utilize steam of low quality but can lead to an overspeed problem in startup of the turbine due to the increased mass of the water on the turbine blading.

A Terry turbine is an impulse noncondensing type turbine, which means that it is driven by impulse force rather than reaction force. An impulse turbine is effected by a direction change in the fluid stream leaving the blading, but it is not effected by expansion of the fluid leaving the blade. There is no velocity change across the moving blade in an impulse turbine like there is in a reaction turbine. It is not effected by the fluid stream leaving the blade, only the fluid stream striking the blade. Therefore, it does not matter if the water flashes leaving the blade; however, the mass and velocity of the fluid striking the blade does matter. Water has more mass per volume than steam; therefore, at any given velocity it will strike the impulse blade with more force than steam at the same velocity. (This means that more work is being done by the water because of the difference in mass per volume.)

A Terry turbine is protected from overspeeding by a mechanical tripping mechanism. A mechanical key, whose position is a function of the centrifugal force generated by motor speed will trip a mechanical lever in the turbine casing during turbine overspeed conditions. This will shut the turbine steam supply valve and stop the turbine.

Chapter 11 Definitions

STOP VALVE

- An emergency valve located upstream of the turbine control valve that can be rapidly closed to isolate the turbine steam supply for turbine or plant protection.

CONTROL VALVE

- The valve or group of valves located between the stop valve and the turbine that regulates the flow of steam to the turbine and controls the turbine speed or turbine generator load.

COMBINED INTERMEDIATE VALVE

- A valve located in the steam flow path between the moisture separator-reheater and the low pressure turbine that has two valve seats inside one valve body. The first part of the valve, the intermediate stop (reheat stop) valve, trips shut on a turbine trip. The second part of the valve, the intermediate control (intercept) valve, modulates closed during a turbine overspeed condition.

EXTRACTION NON-RETURN VALVE

- A valve in the extraction steam line to a feedwater heater that automatically closes on a trip of the main turbine or a high water level in the heater.

GOVERNOR

- A device used to control steam flow to a turbine to maintain a constant shaft speed under varying load conditions.

FRONT STANDARD

- A large box-like structural member with sliding feet that supports the forward bearing of the high pressure turbine and part of the weight of the high pressure turbine shell.

CRITICAL SPEED

- The resonant speed of a rotating shaft, which can produce very high amplitude vibrations that are potentially destructive.

JOURNAL BEARING

- An axial bearing that restrains the radial movement of a rotating shaft. In horizontal machines, the journal bearings are also used to support the weight of the rotating shaft.

THRUST BEARING

- A bearing that absorbs the axial thrust experienced by a rotating shaft. In vertical machines, the thrust bearing also supports the weight of the shaft.

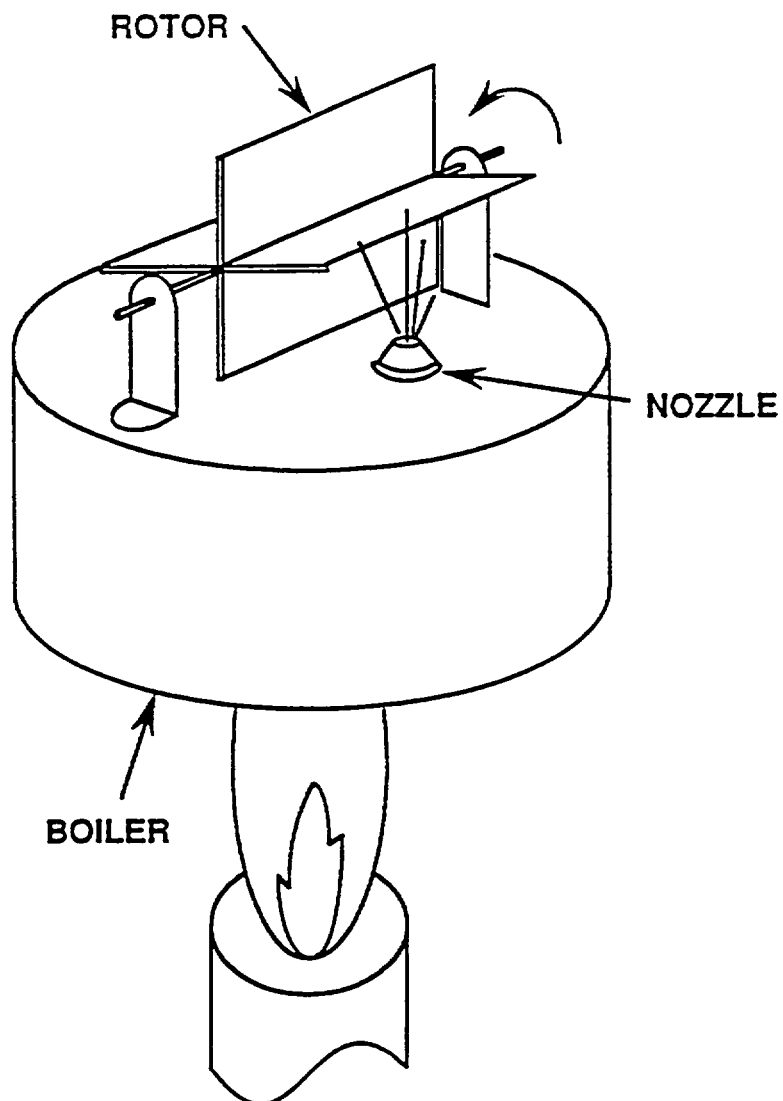


Figure 11 - 1. Impulse Turbine Principle

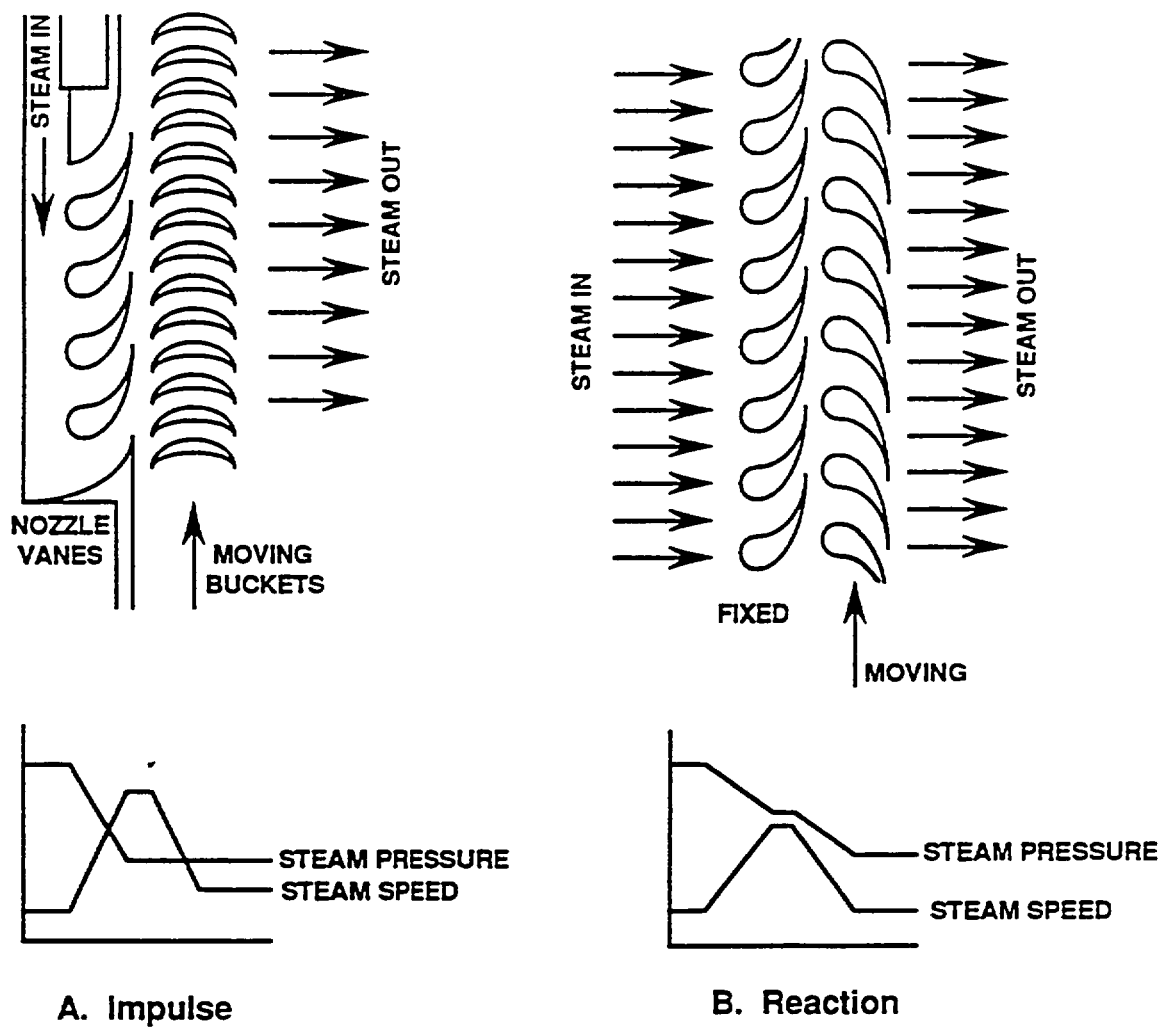


Figure 11 - 2. Ideal Turbines

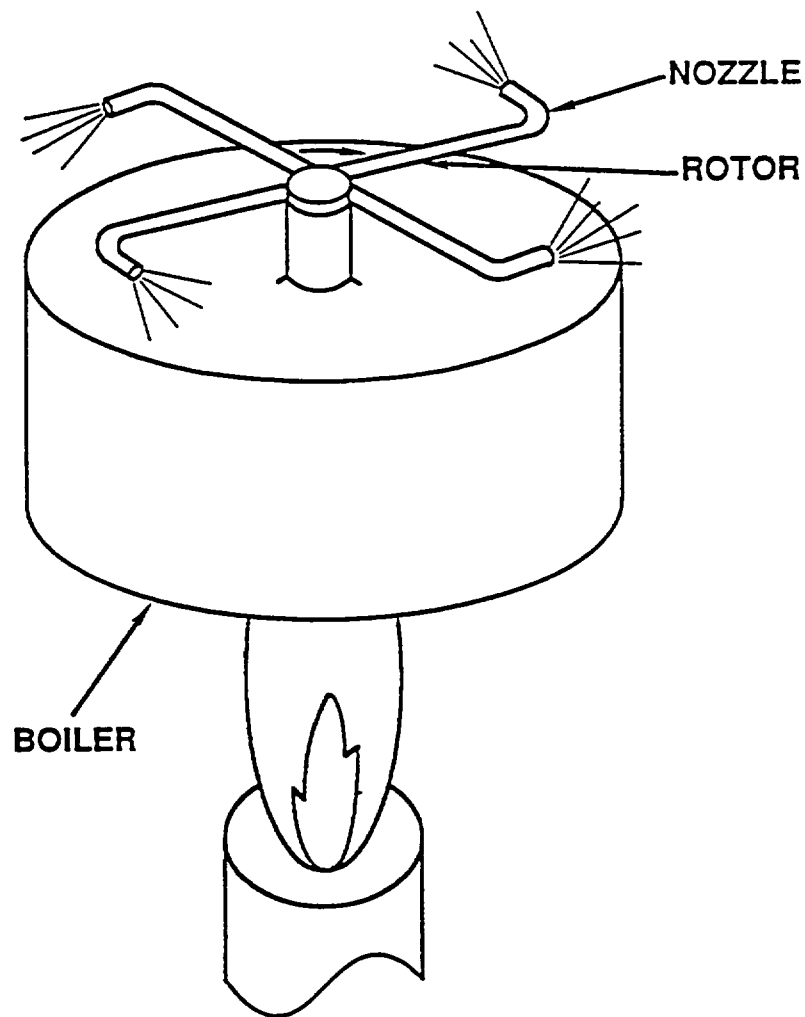


Figure 11 - 3. Reaction Turbine Principle

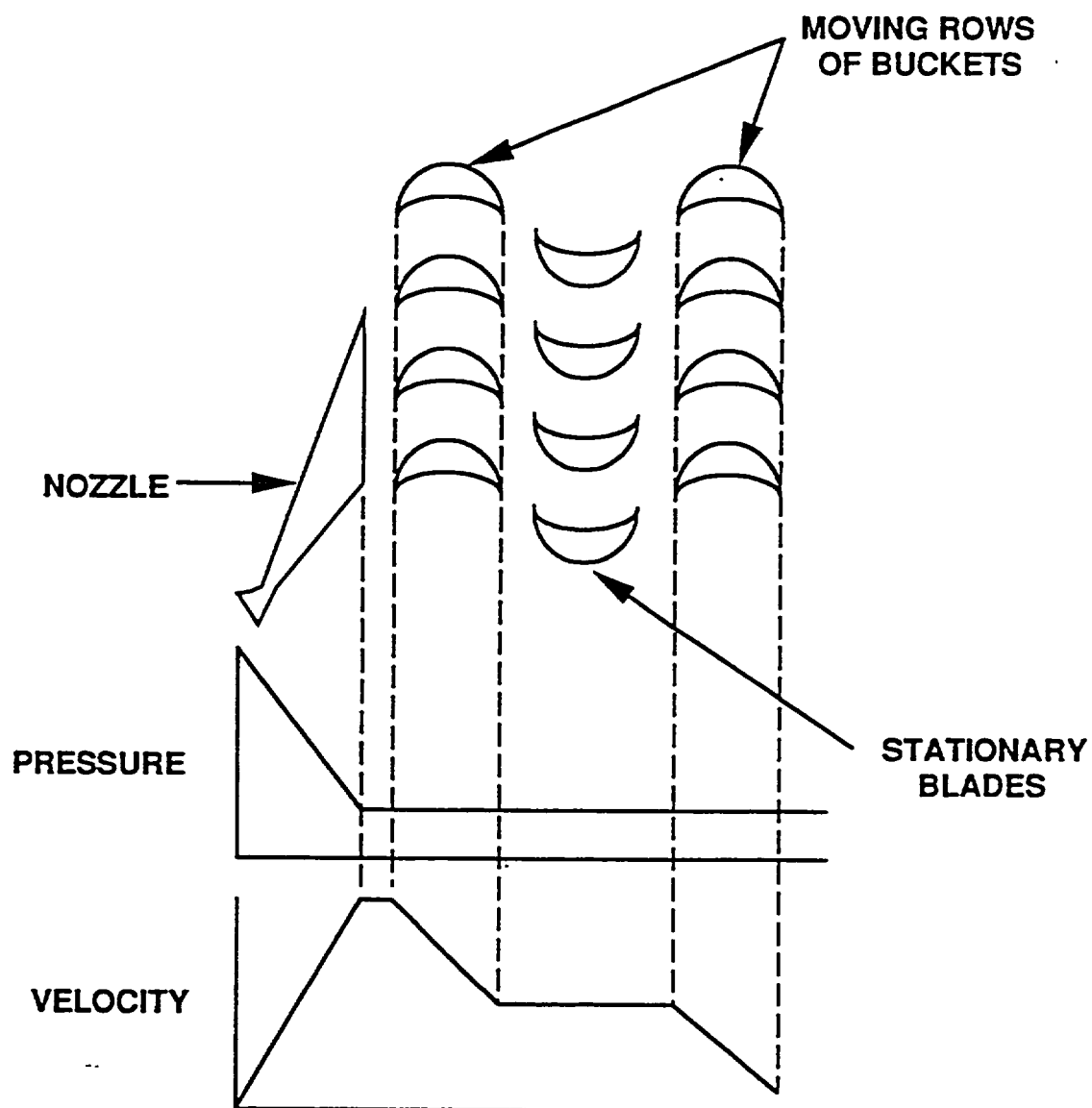


Figure 11-4. Velocity Compound Staging (Curtis Stage) Pressure-Velocity Diagram

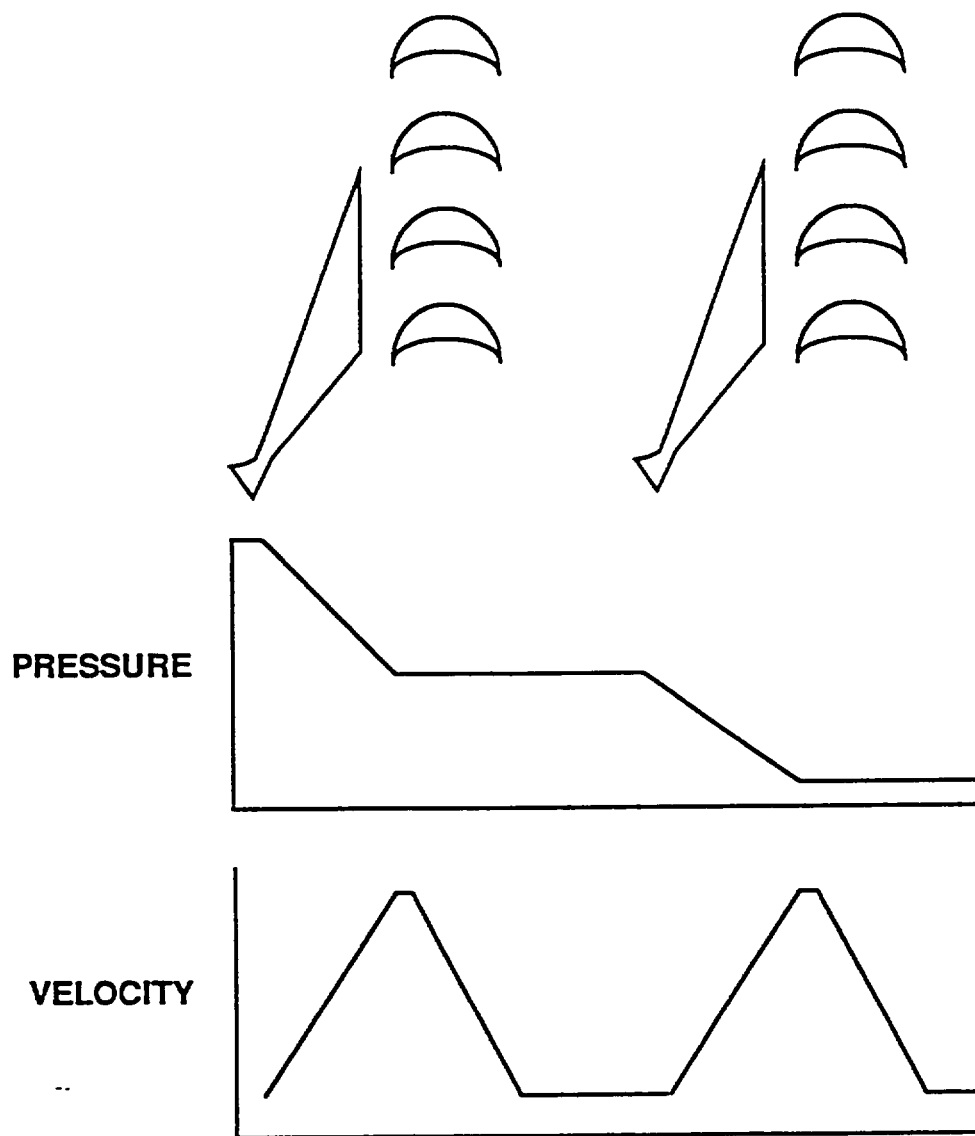


Figure 11-5. Pressure Compound Staging Pressure-Velocity Diagram

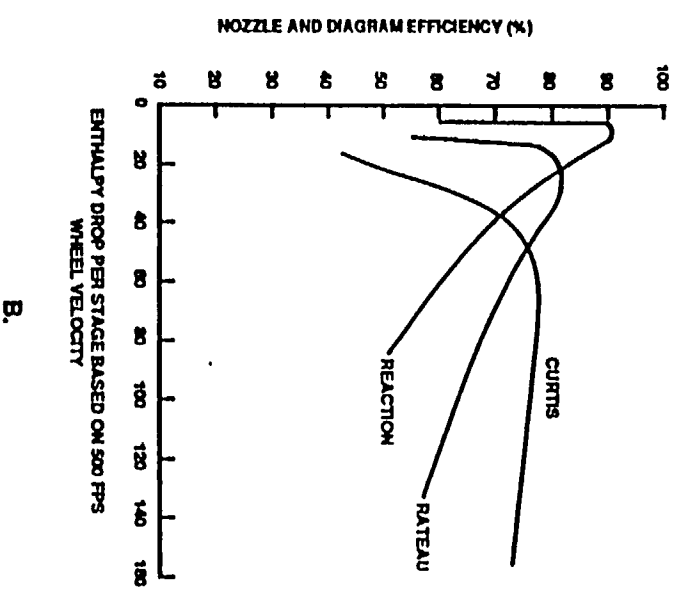
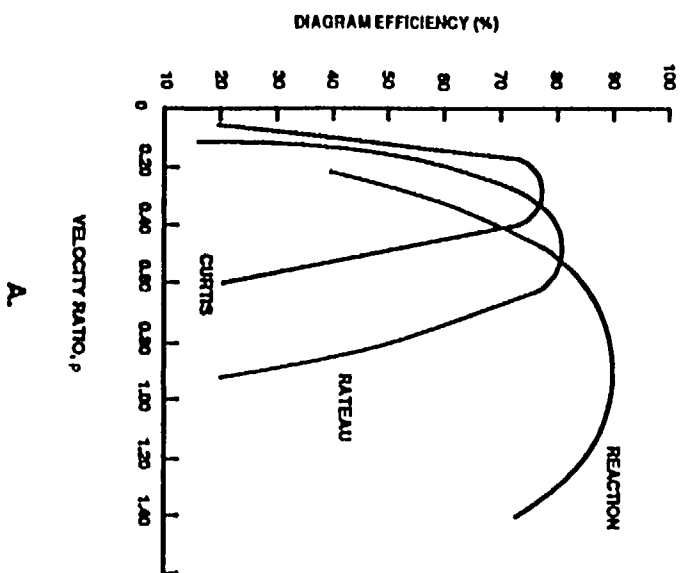
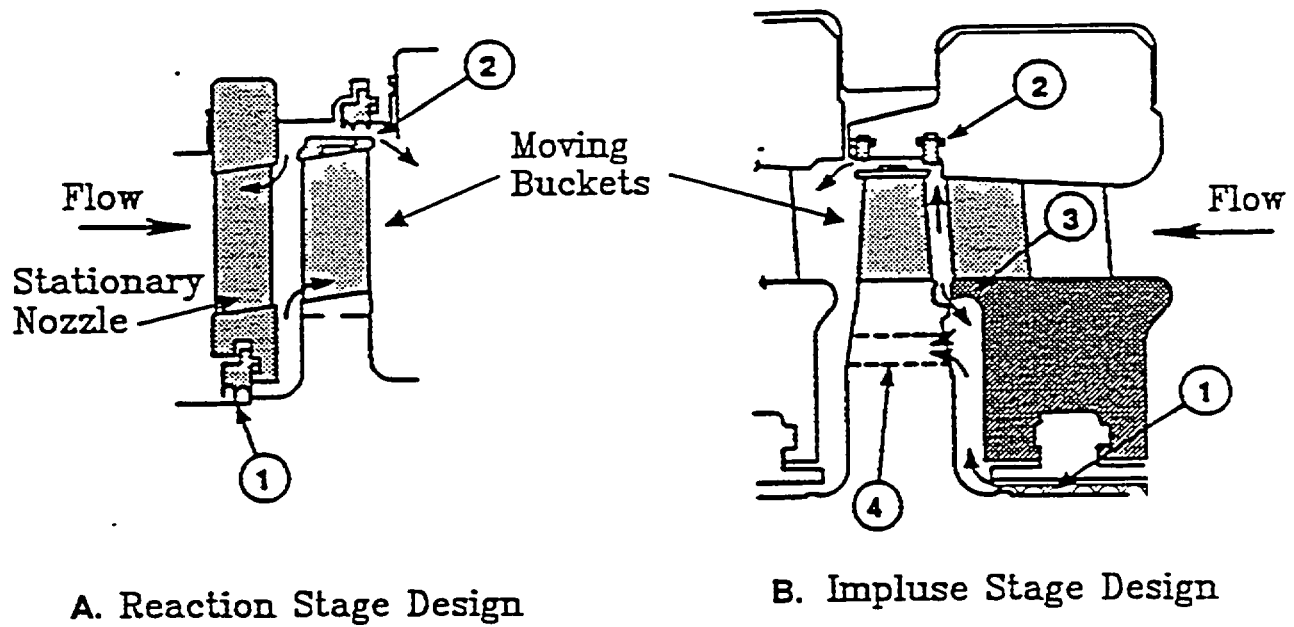


Figure 11 - 6. Reaction and Impulse Efficiencies



Notes:

1. Shaft Labyrinth Seal
2. Blade Tip Packing
3. Spill Strip
4. Balance Hole

Figure 11-7. Interstage Sealing

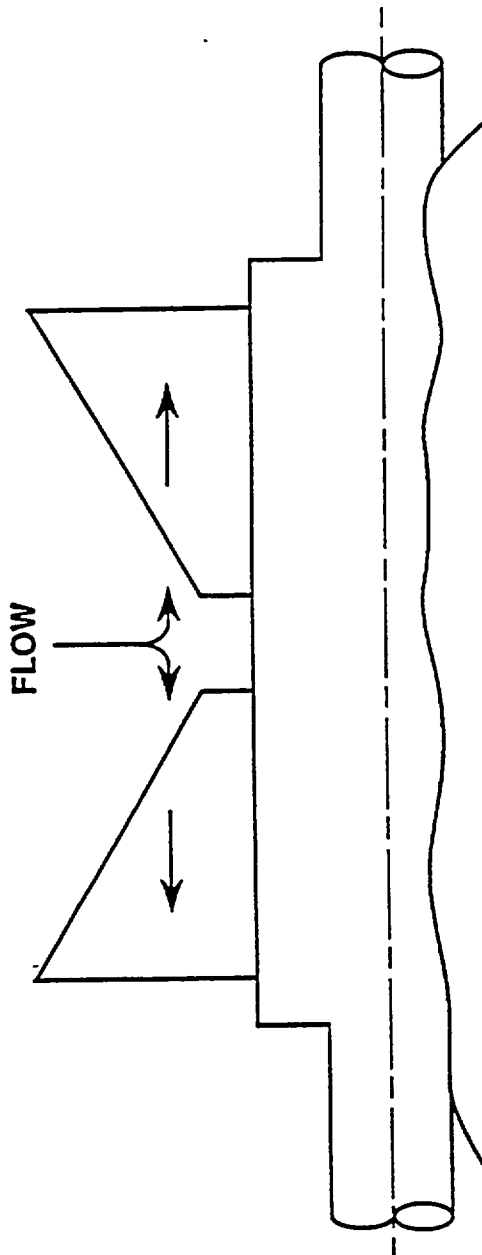
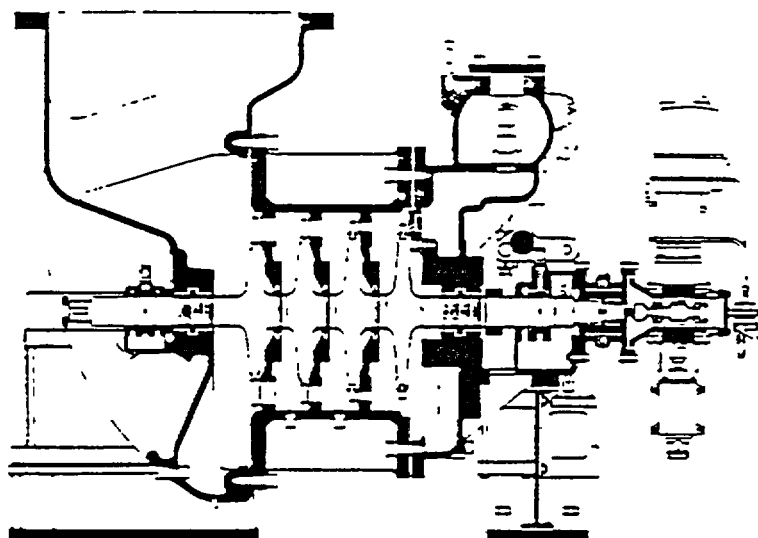
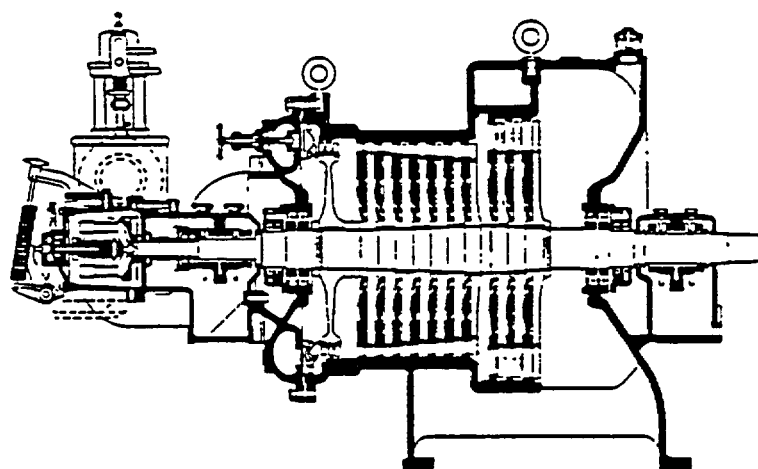


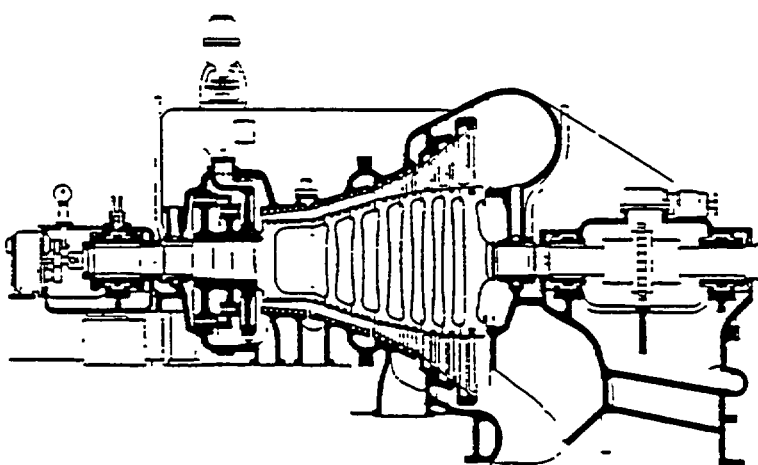
Figure 11 - 8. Double-Flow Rotor



(a) Integral Rotor Discs



(b) Shrink-fit and Keyed Rotor Discs



(c) Forged Separate Disc Section Rotor

Figure 11-9. Rotor Types

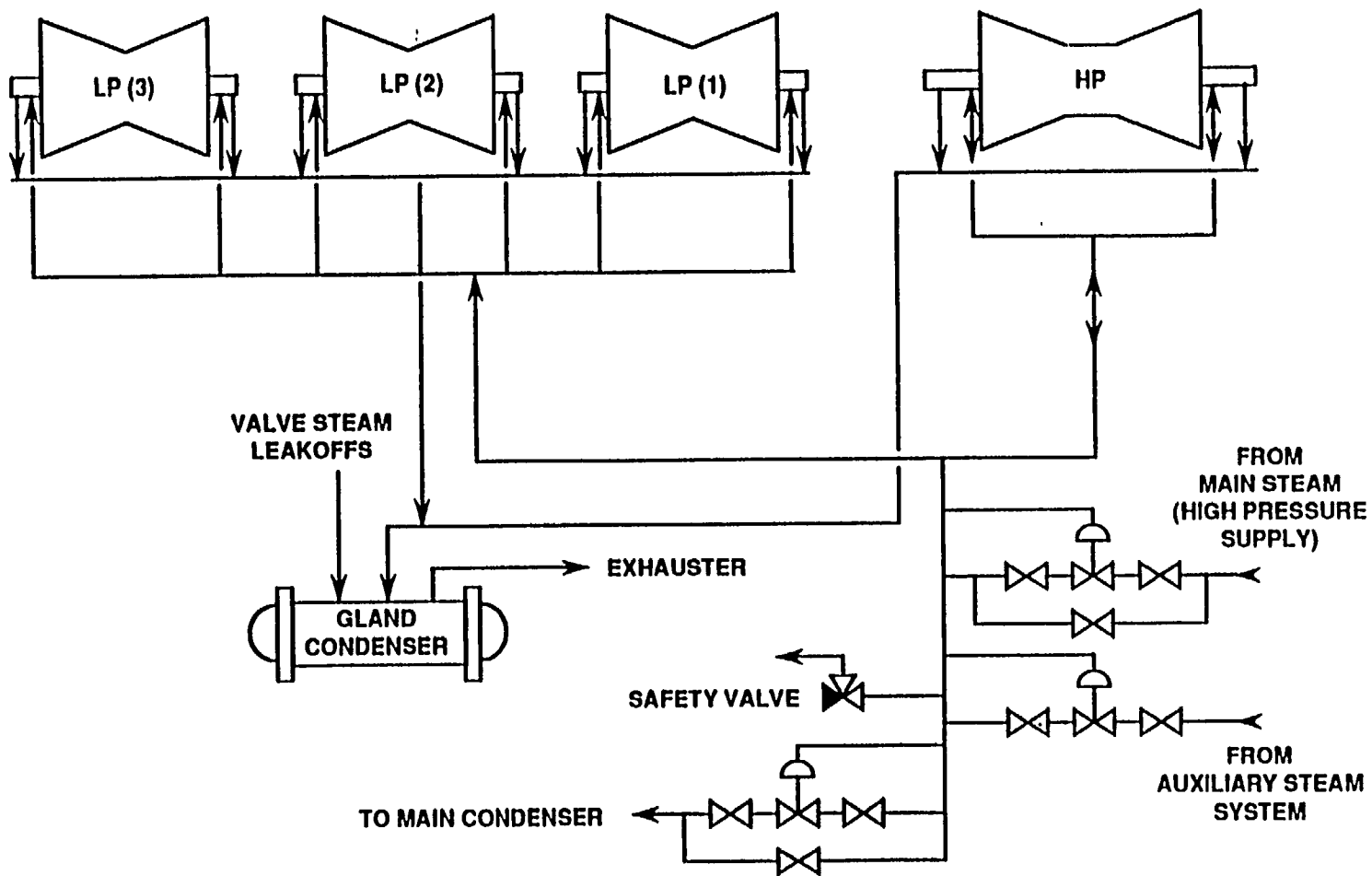


Figure 11 - 10. Shaft Gland Sealing System

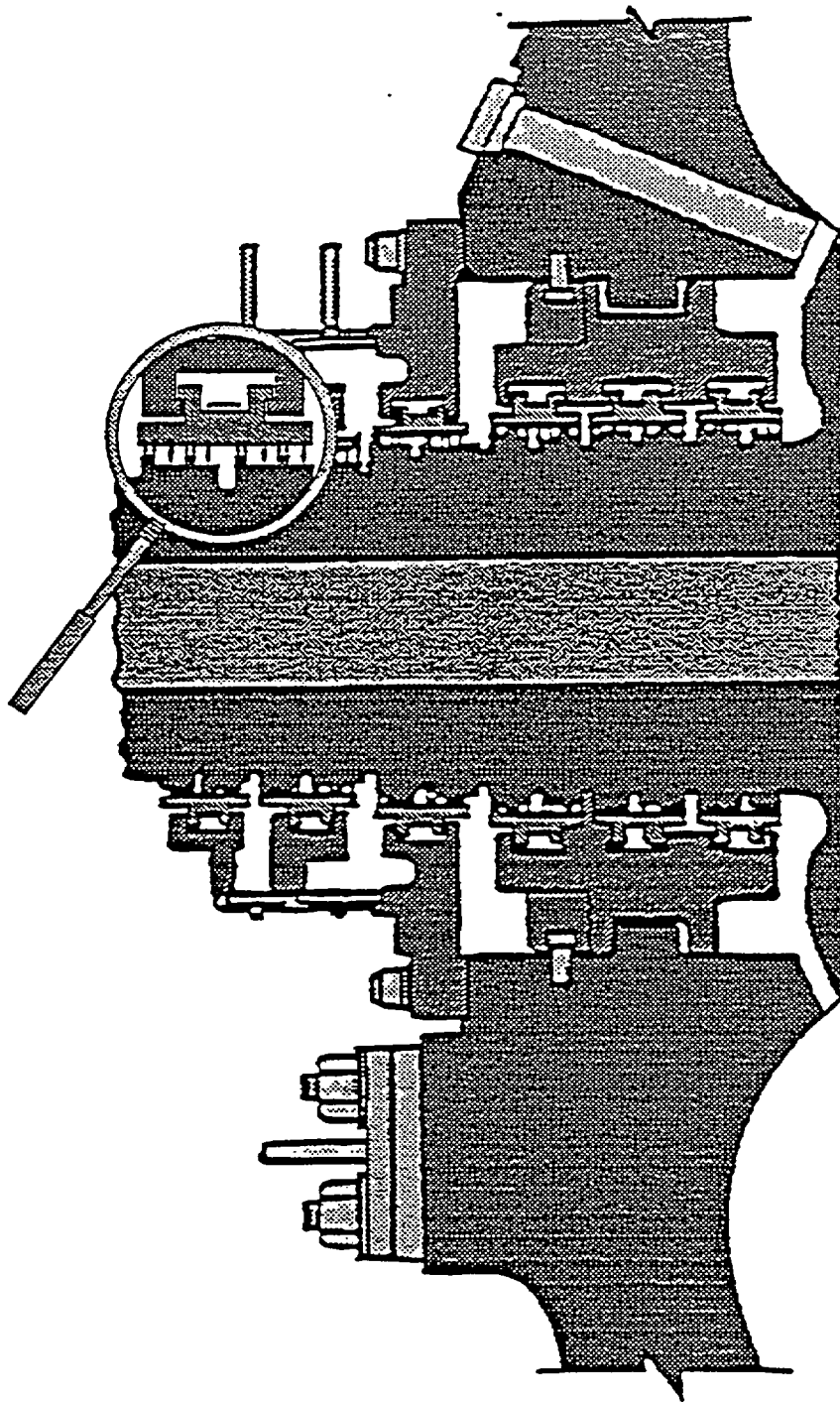
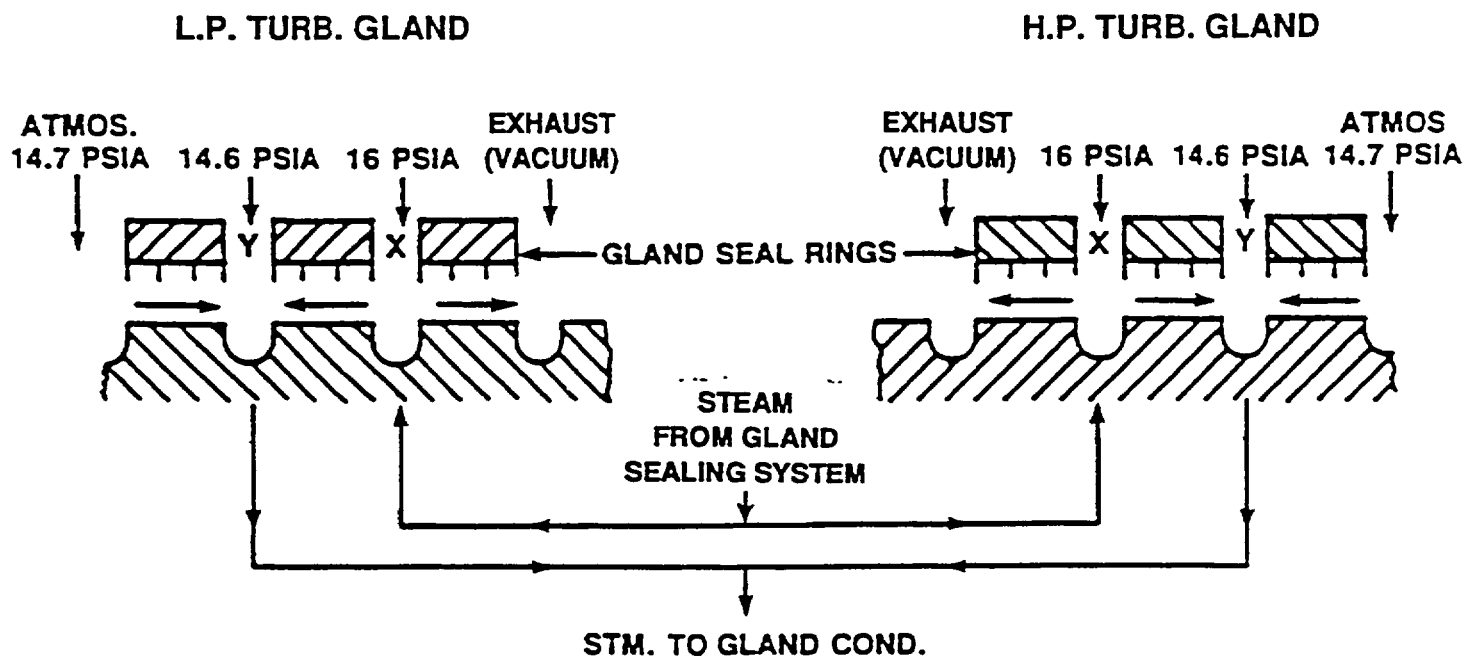


Figure 11-11. Labyrinth Seals

A. TURBINE AT NO OR LOW LOAD



B. TURBINE AT HIGHER LOADS

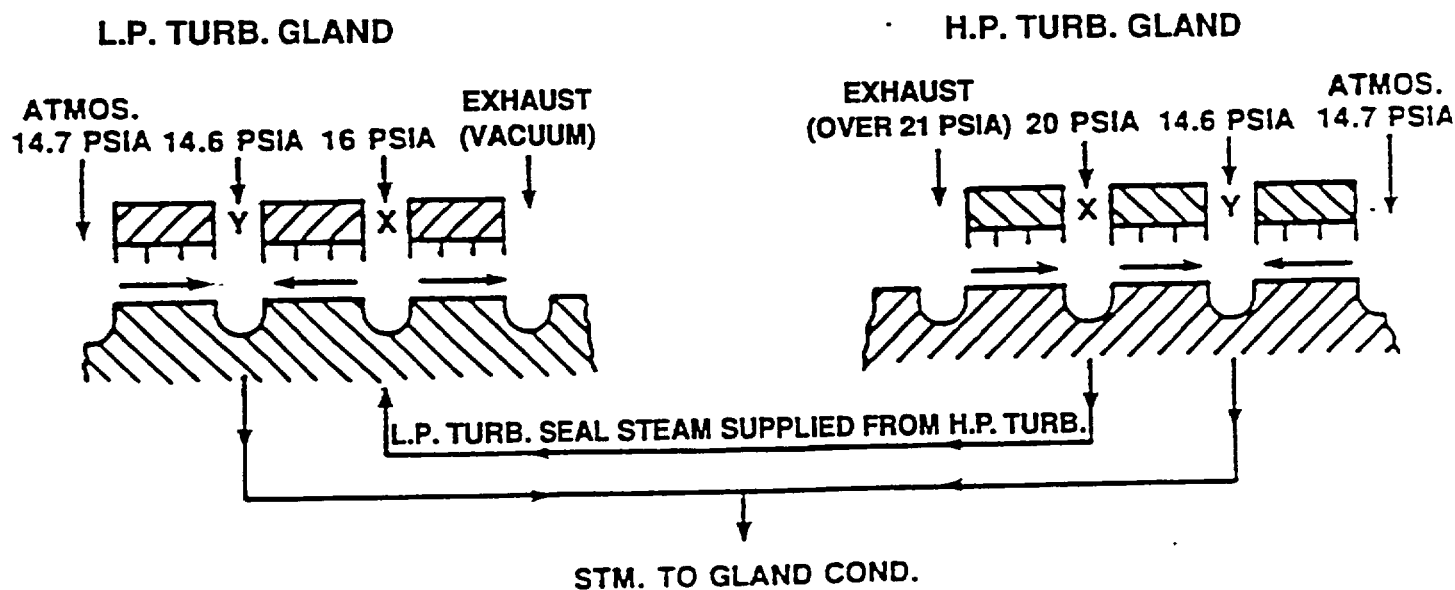
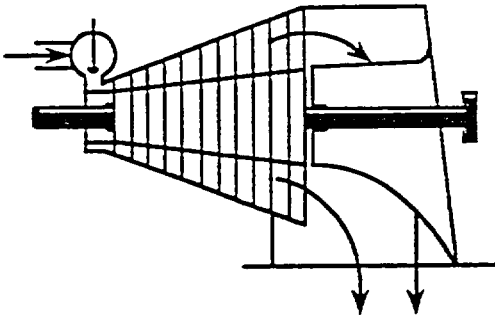
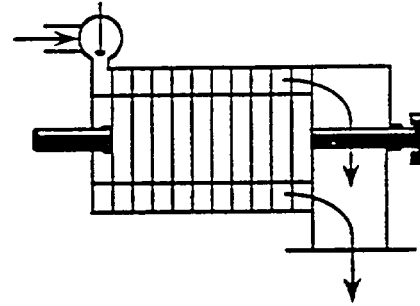
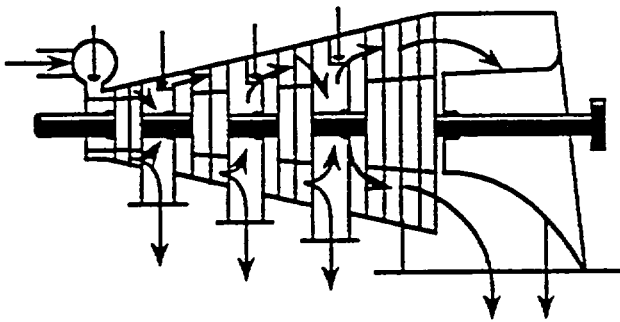
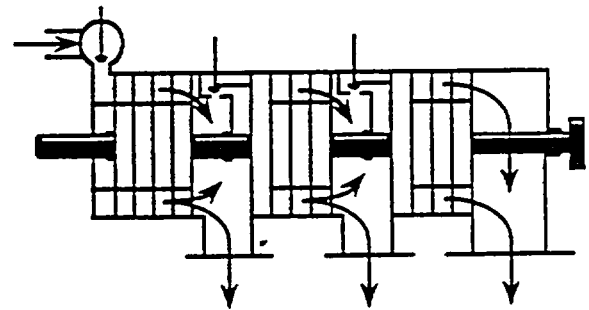
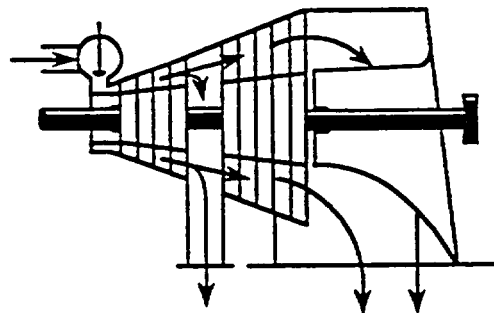
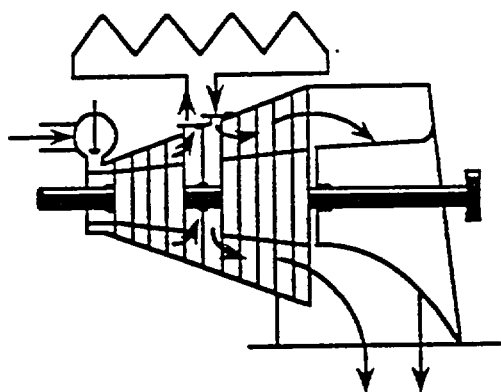
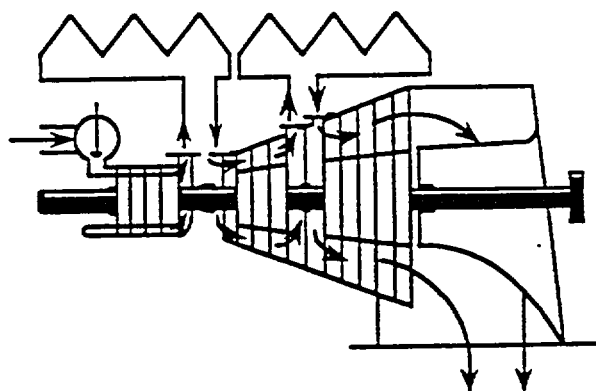
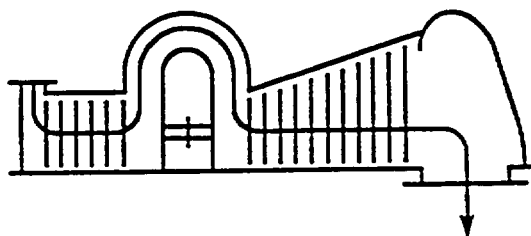
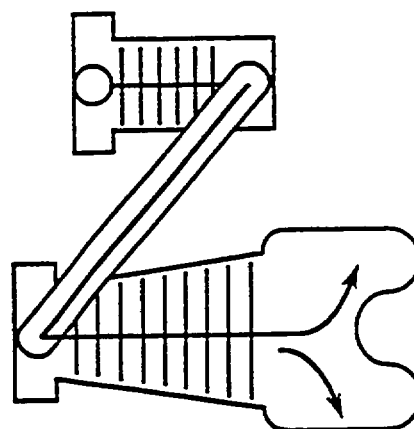
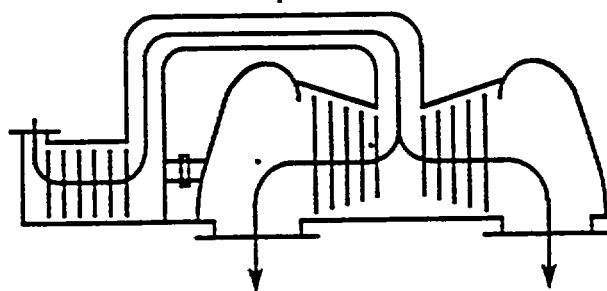


Figure 11-12. Gland Seal Steam Distribution

**A. Straight-Flow Condensing****B. Straight-Flow Noncondensing****C. Triple Automatic Extraction Condensing****D. Double Automatic Extraction Noncondensing****E. Single Nonautomatic Extraction Condensing****Figure 11 - 13. Turbine Types**

**F. Single Reheat Condensing****G. Double Reheat Condensing****H. Tandem-Compound****I. Cross-Compound****J. Tandem-Compound, Double-Flow****Figure 11 - 13. Turbine Types, Continued**

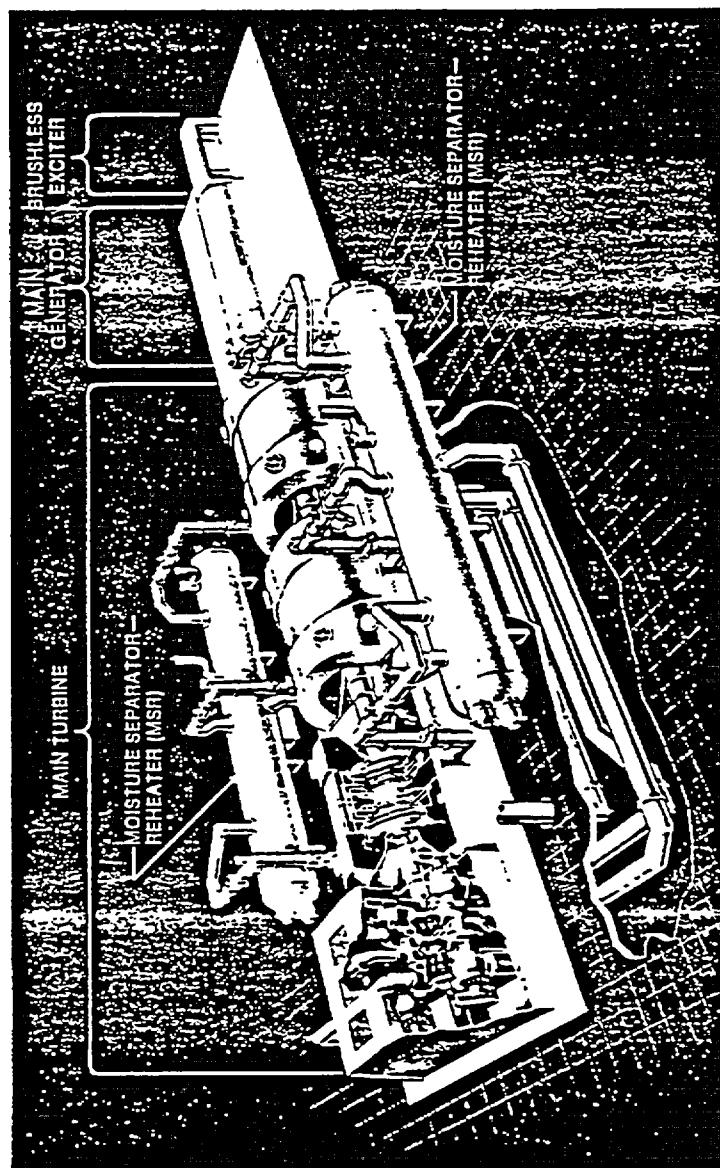


Figure 11-14. Four Cylinder Nuclear Unit

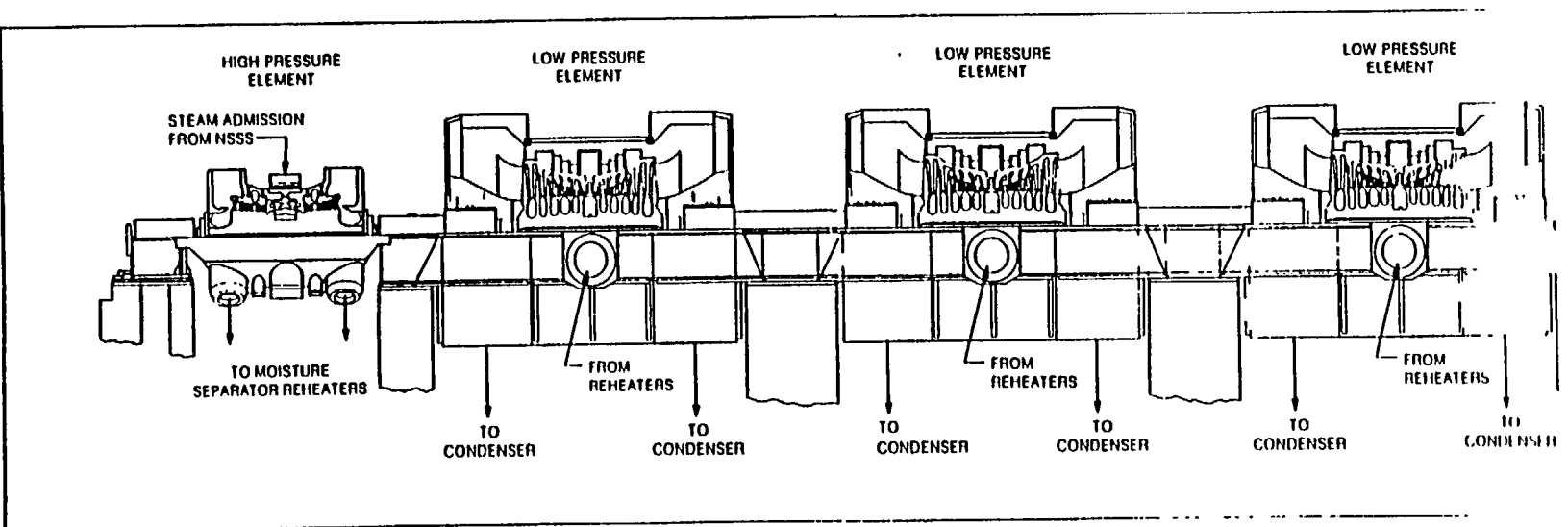


Figure 11-15. Four Cylinder Turbine, Cross Section

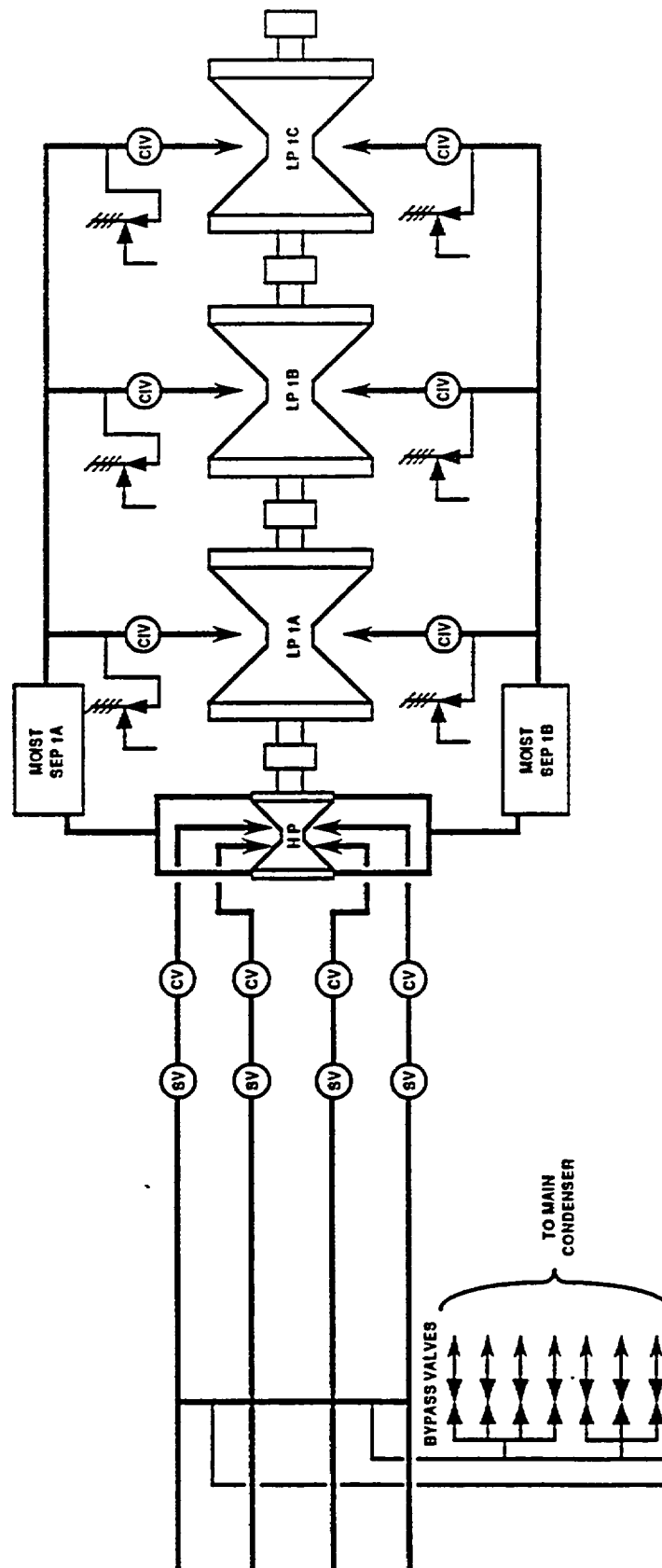


Figure 11-16. Main Steam System

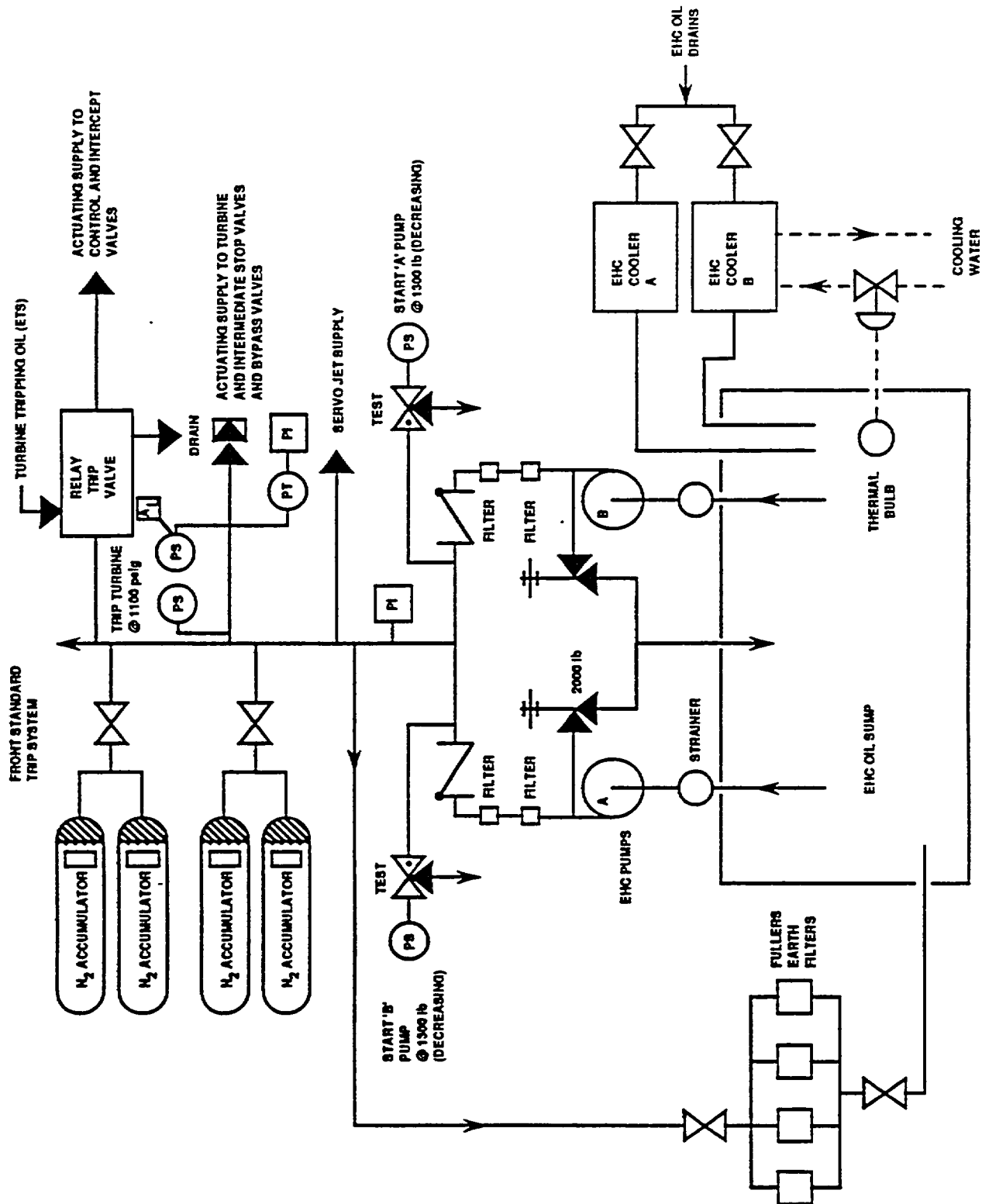


Figure 11-17. EHC System Hydraulic Power Unit

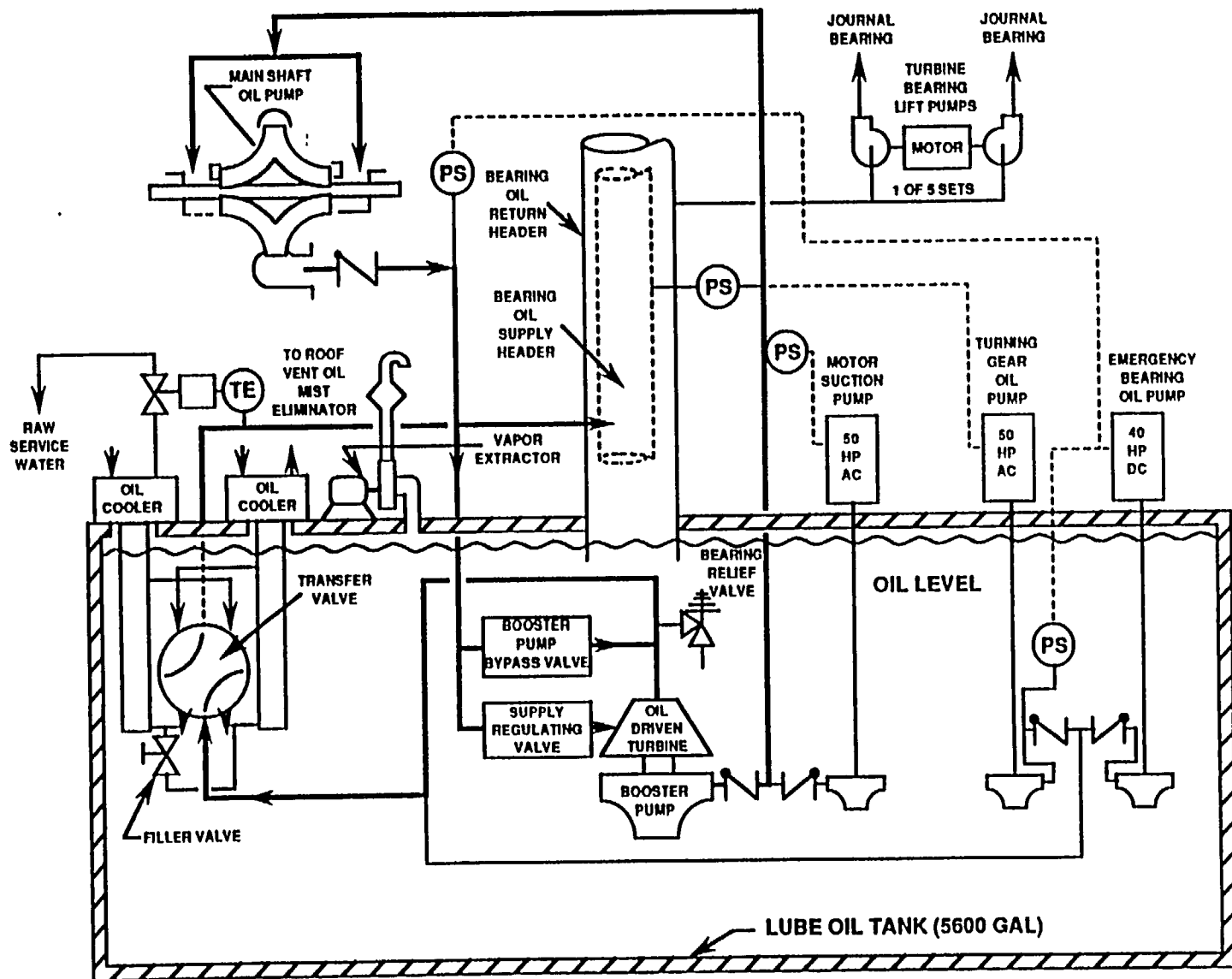


Figure 11-18. Turbine Lube Oil System

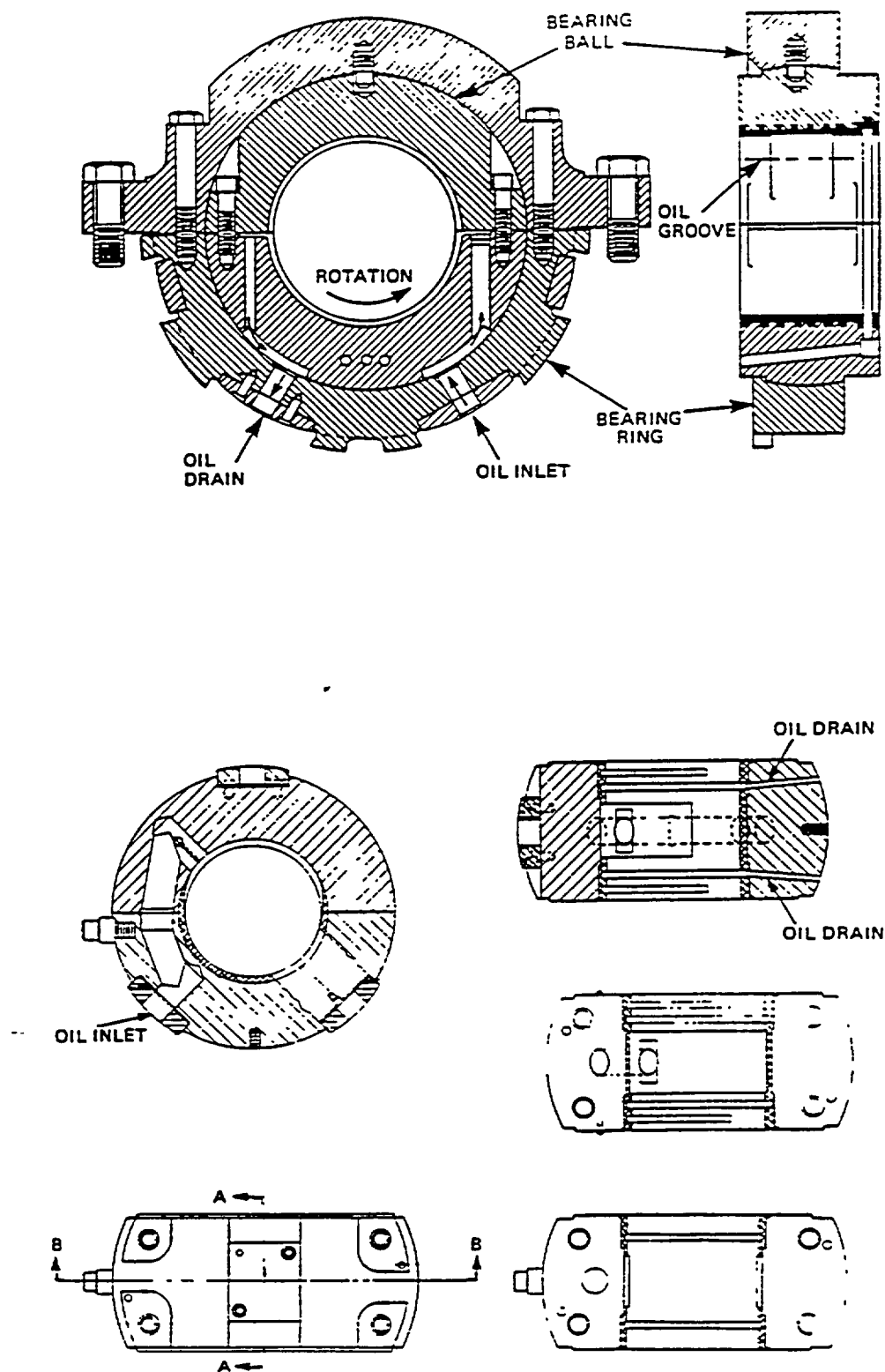


Figure 11-19. Typical Journal Bearing

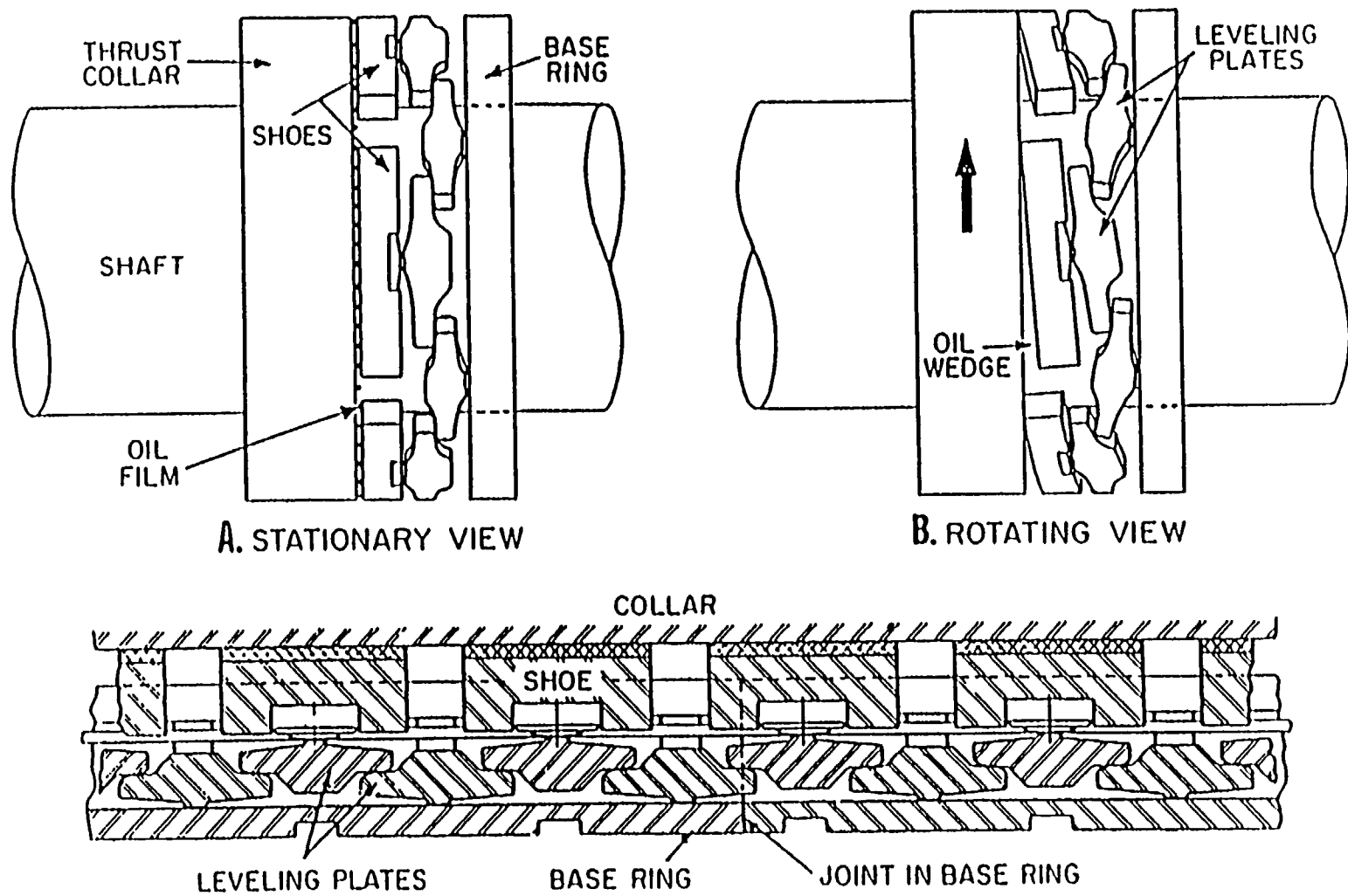


Figure 11-20. Thrust Bearing

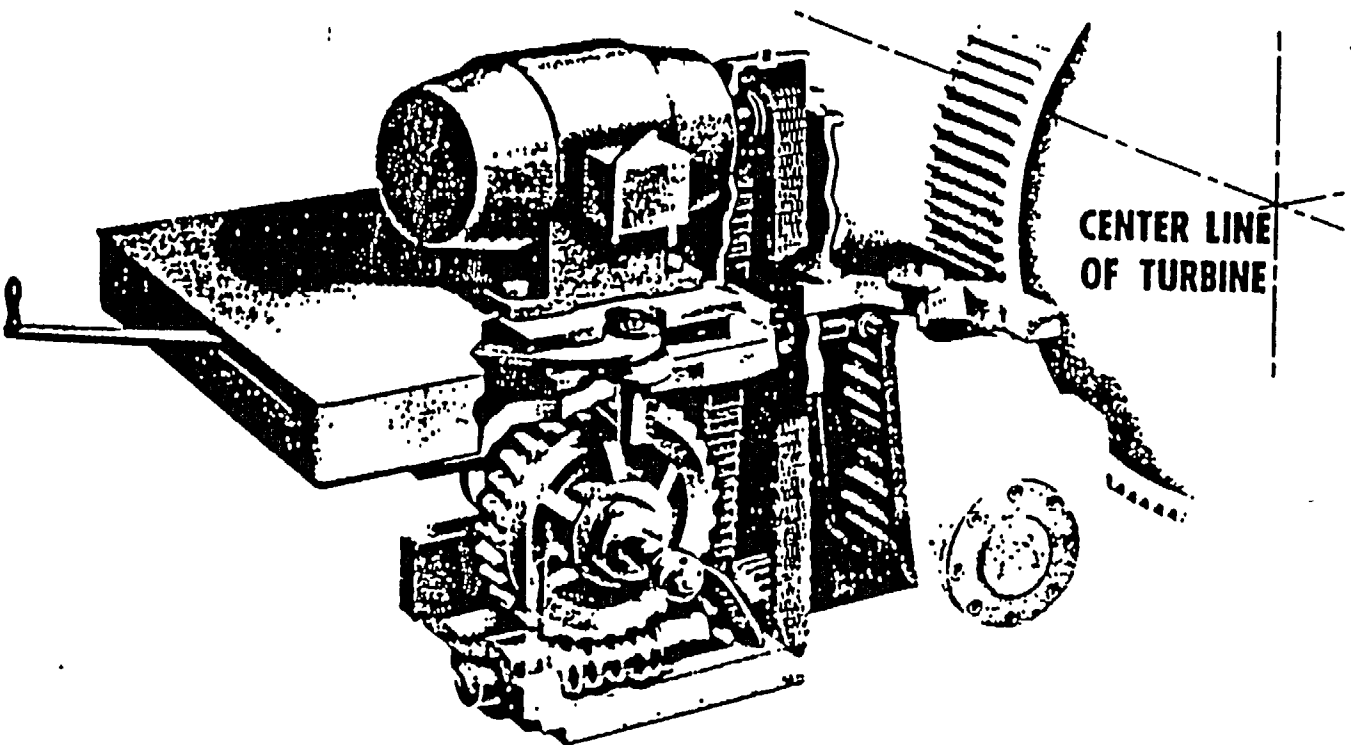
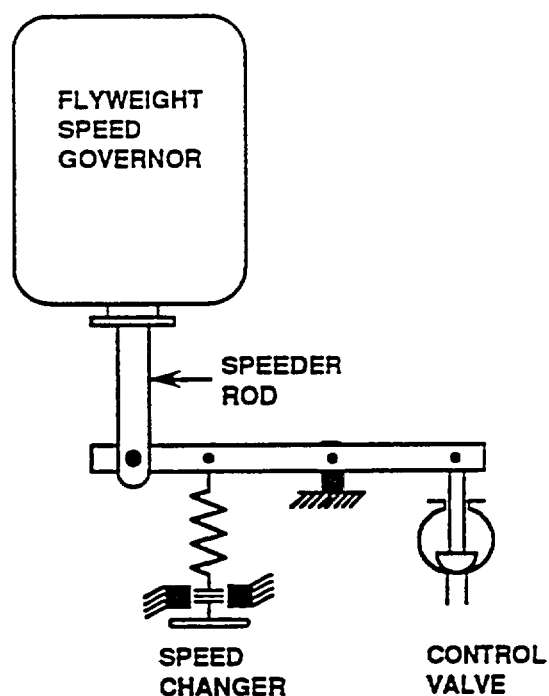
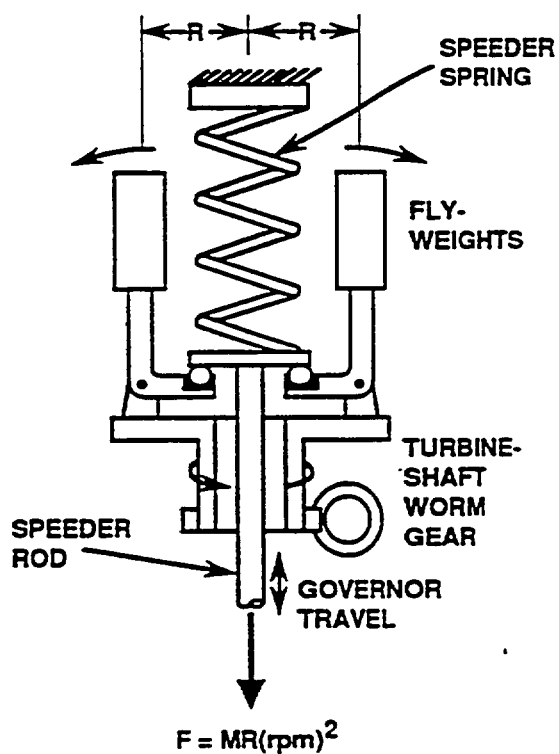


Figure 11-21. Side-Mounted Turning Gear



A. Speed-changer spring alters force acting on the steam-control-valve lever



B. Flyweight governor balances the force of spring and weights, moves speeder rod

Figure 11-22. Flyweight Governor System

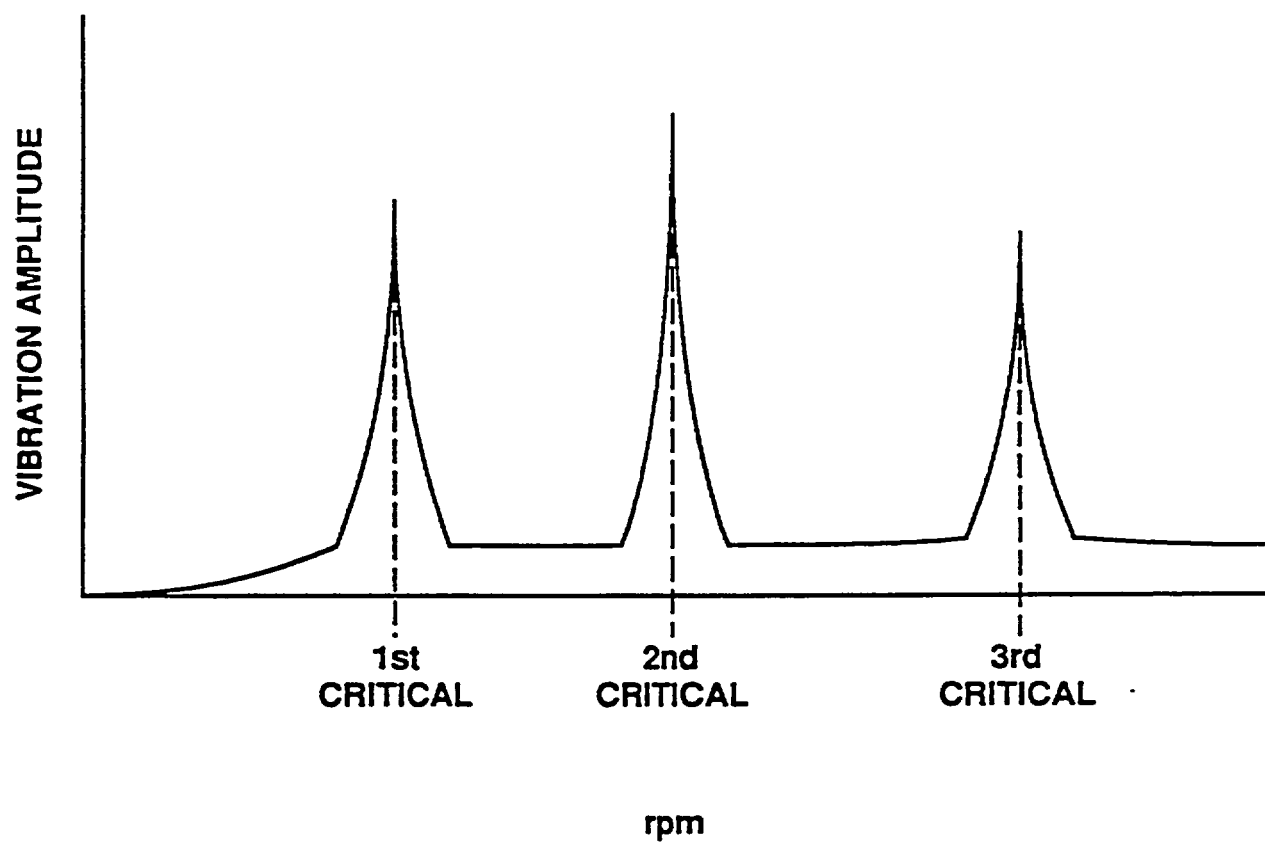


Figure 11-23. Rotor Critical Speeds